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# Achieving Long-term Energy, Transport and Climate Objectives: Multidimensional Scenario Analysis and Modeling Within a Systems Level Framework

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**Achieving Long-term Energy, Transport and Climate Objectives: Multi-dimensional Scenario Analysis and Modeling Within a Systems Level Framework**

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*To Lindsay.*

*For the years of unwavering support and sacrifice, I owe you.*

*For all the fun and adventure we've had along the way, I thank you.*

*For constantly being willing to take the road less traveled, even though it's not always clear where it will take us, I'm so grateful for you.*

*I think we make a pretty good team.*

# Abstract

The energy challenges facing society are as varied as they are great, and for this reason energy has become a key area to address in the twenty-first century. Central among these concerns is the specter of global climate change. The impact of energy production and consumption on the earth's climate system has been well documented, and scientific studies now suggest that annual greenhouse gas emissions must be cut 50 to 80 per cent worldwide by 2050 in order to stabilize the climate and avoid the most destructive impacts of climate change. Yet, despite the growing consensus for the need to mitigate emissions, the strategies for meeting these ambitious targets have not been clearly defined, and the technology and policy options are not well enough understood. Given this uncertainty, scenario analysis tools have emerged as a useful way to inform the policy debate by envisioning the potential evolution of energy systems over time. This dissertation describes three separate scenario analysis projects, each of which looks at the potential for a dramatic transformation of the energy system over the long term at varying geographic and sectoral scales. First, the 80in50 study analyzes the various pathways for making deep reductions in greenhouse gas emissions across all subsectors of U.S. transport system. The CA-TIMES project then takes this work to the next level by developing an energy-engineering-environmental-economic optimization model for the California energy system, in order to bring economics and dynamics into the analysis, as well as to study the interactions between transport and the various other energy producing and consuming sectors. Finally, a collaborative project with scientists at the International Institute for Applied Systems Analysis (IIASA) is described, in which a global systems engineering optimization model (MESSAGE) and a global climate model (MAGICC) are

jointly utilized to evaluate synergies and trade-offs between a variety of energy objectives (climate mitigation, air pollution, energy security, and affordability).

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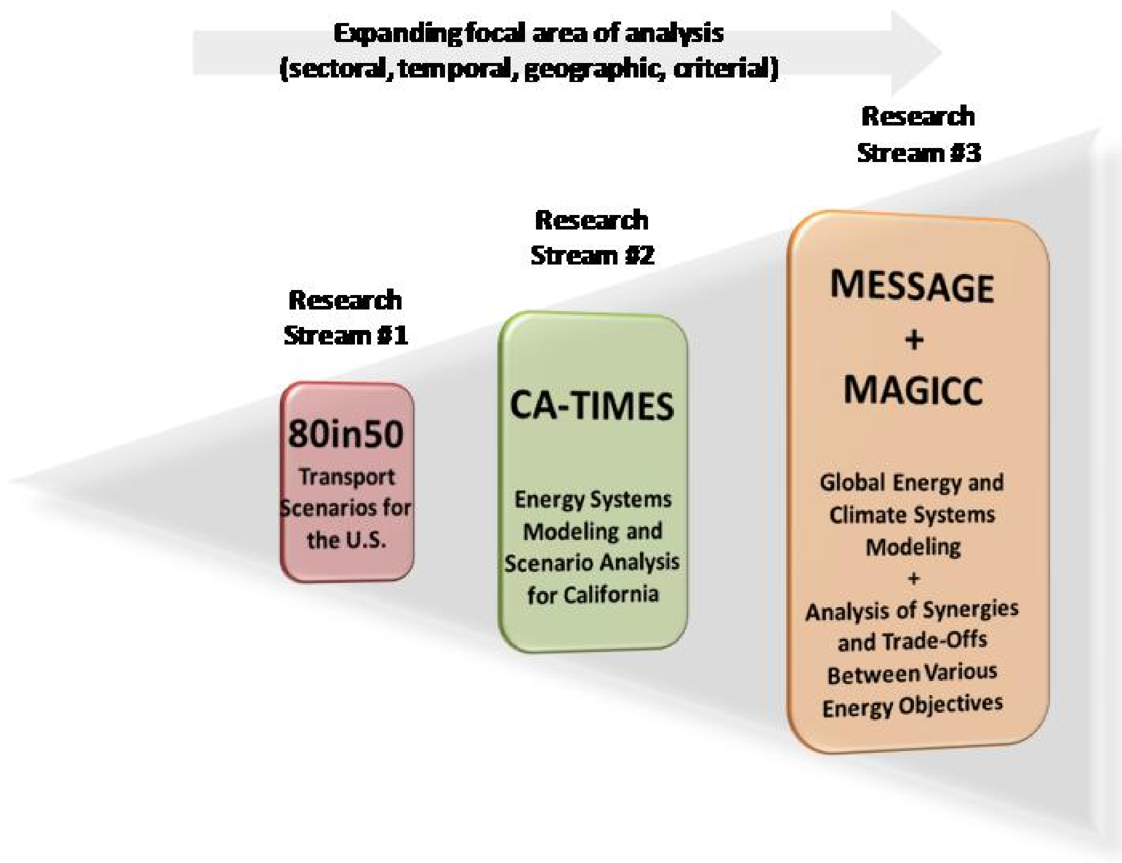
# FOREWORD

The structure of this dissertation incorporates both traditional and non-traditional elements, and for this reason I believe it is useful here at the outset to provide a brief overview of how the three chapters of my thesis fit together and, moreover, how the three projects underlying them originally came into being. My dissertation work really started in earnest in early-2008, after finishing my M.S. degree and beginning the so-called "80in50" project under the direction of Dr. Christopher Yang. The original 80in50 study focused on the California transportation sector, and once it was completed, Chris and I took the analysis to the next level by looking at deep greenhouse gas reduction scenarios for the entire U.S. The latter research is described in Chapter I of this dissertation. However, due to the limitations of the 80in50 research effort, there were discussions at that time within the UC-Davis STEPS Program to develop an energy-engineering-environmental-economic (4E) MARKAL-TIMES systems model for the state of California, which would bring economics and dynamics into the scenario development process, as well as interactions between the transport sector and the various other energy producing and consuming sectors within the California energy system. As one might imagine, it is quite an undertaking to build an energy systems model from scratch, and actually in my case it has taken about two and a half years of sometimes part-time, sometimes full-time work to bring the CA-TIMES model to the current stage of development. A fairly detailed description of the model is provided in Chapter II, along with scenario analyses looking at how deep reductions in greenhouse gas emissions might be made across the entire California energy system in the long term. Finally, Chapter III of my dissertation describes a collaborative research effort with scientists at the International Institute for Applied Systems Analysis (IIASA) in Laxenburg, Austria. In the summer of 2009, I participated in IIASA's annual Young Scientists Summer Program, with the intention of supporting the scenario development process for the Global Energy Assessment. Due to the success of my summer project at IIASA and also because of the unique contributions this analysis adds to my Ph.D. research portfolio, I eventually decided to include the work in my dissertation. In particular, the research at IIASA expands the focal area of my scenario analyses to the global level and at the same time brings other energy objectives – in addition to climate mitigation – into consideration, such as energy security and air pollution.

Each of the three main chapters of my dissertation is distinct, in the sense that each focuses on a distinct research project; however, at the same time, they are all closely related, as they fall under the more general umbrella theme of long-term energy modeling and scenario analysis to support policy. After all, the central objective of my dissertation research is to understand the potential evolution of energy and climate systems over time, considering multiple sustainable development goals and advanced technologies and fuels. The three research projects simply differ in terms of their system boundaries and in the methods that are employed. For these reasons, I prefer to think of the three chapters of my dissertation as unique "Research Streams", and I have organized these three streams into a logical sequence so that they build off each other at each stage. As the figure below illustrates shows, the focal area, or scope, of my research expands as my dissertation progresses. Depending on the stage of the analysis, this expansion is sectoral, temporal, geographic, and/or criterial in nature.




The three dissertation chapters are, for the most part, self-contained. Each possesses its own introductory material, methodological description, discussion of results, conclusions, and acknowledgements. The only exception is the shared introduction of Part One, which applies to both the 80in50-US and CA-TIMES research streams. Part Two of the dissertation contains only the third chapter, which focuses on the energy trade-offs research stream. Note that the first and third chapters of the dissertation are rather succinct in nature, as they either have already been published elsewhere or draw upon other studies and model documentation, which themselves have been previously published. In contrast, the second chapter is rather long because it describes a model (CA-TIMES) that has never before been discussed in the publicly available literature. As with any complex model, a fair amount of prose is required to provide a reasonably thorough explanation.

# EXECUTIVE SUMMARY

## Chapter I

The first chapter of this dissertation explores several scenarios which achieve 50-80% reductions in US transportation sector carbon emissions below 1990 levels by 2050 through incorporation of significant technological and behavioral changes. A Kaya framework that decomposes GHG emissions into the product of four major drivers—population (P), transport intensity (T), energy intensity (E), and carbon intensity (C) – is integrated in our scenario analysis model, LEVERS, to analyze mitigation options and emissions. In addition, our LEVERS framework includes all major transport subsectors—light duty vehicles, buses, heavy-duty trucks, rail, aviation, marine, agriculture, off-road, and construction. The values for reduction potential from various options in each of the subsectors come from an extensive review of the literature.

The scenarios that are developed using the LEVERS model illustrate the enormous challenges associated with making deep GHG reductions in the US transportation sector. While they represent only a small subset of all potential futures that could potentially meet the 80% reduction target, they provide value by showing the diversity of approaches that might be pursued. These scenarios, first and foremost, are meant to convey the scale and scope of the changes required to meet this aggressive target and to motivate the aggressive action (i.e., policy and technological development) that will be required in all transport subsectors and on all fronts (vehicles, fuels, and travel demand management) over the coming decades.

Several *Silver Bullet* scenarios are created in order to show that no one mitigation option can singlehandedly meet the ambitious GHG goals, especially since total travel demand (P x T) in each subsector is expected to increase significantly by 2050. This puts a large burden on vehicle and fuel technologies (E x C) to decarbonize, and by our estimates it is unreasonable to think a single technology approach can shoulder this burden entirely on its own, given the diversity of vehicle types and requirements in the transportation sector.

When multiple technological strategies are combined together in a portfolio approach, however – assuming the wide array of technical, economic, social, and policy challenges can be overcome – the potential for emission reductions could be great, as the *50in50* and *80in50* scenarios highlight. This mixed strategy approach would include (1) restraining the growth in travel demand with strong transport and land use planning policies, and (2) targeting advanced technologies and fuels to the subsectors where they are most feasible. Because multiple options are employed, the portfolio approach reduces the required level of vehicle and fuel technology development and usage for any given mitigation strategy. A portfolio approach also helps to reduce the sensitivity of GHG emissions to any one technology, resource, or behavioral change and the associated risks if the strategy does not succeed.

Constraints on primary resources and the penetration of new technologies into the market could put limits on how deeply US transport emissions might be reduced, however. In particular, biofuel production is limited by the total amount of biomass resources available in the US and globally. The use of electric-drive vehicles will not likely be limited by resource constraints, but challenges will arise from the timing of technology development and cost reductions in light of the slow turnover of vehicle fleets, as well as from the limited applicability of electricity and hydrogen outside of on-road, rail, and perhaps some marine applications. Deep emission reductions are also particularly sensitive to fuel carbon intensities. This depends on the land use impacts (direct and indirect) of expanded biomass production and the potential of CCS to decarbonize fossil-based electricity and hydrogen production, neither of which is fully understood at this time.

The extent to which the transport sector will ultimately need to reduce its emissions is not certain since deep reductions are not yet law and reductions will likely not be equal across all sectors of the economy. But as one of the largest current contributors to total US GHG emissions, transportation must play a major role (IEA, 2008; Yeh et al., 2008). If the US is to have a low-carbon transportation sector by 2050, it will need to expand its policy toolkit in order to adequately address emissions from all subsectors. A diverse, portfolio approach for mitigating GHG emissions necessitates continued research and policy support for improving vehicle and fuel technologies and reducing transport intensity. While the potential carbon impacts of the various technology options are relatively well understood, the impacts of the behavioral options are less so, especially in the non-LDV transport subsectors (UKERC, 2009). Behavioral and structural changes, and policies promoting them, are critically important to alleviate dependence on future technology developments and also to reduce other non-GHG-related problems related to unchecked growth in travel demand, including traffic congestion and fatalities.

## Chapter II

The second chapter of this dissertation describes the development of an energy-engineering-environmental-economic (4E) systems optimization (linear programming) model that represents the vast majority of energy and emission flows within, to, and from California. The CA-TIMES model, as it is called, is built within the well-established MARKAL-TIMES framework and is, thus, extremely rich in bottom-up technological detail. The main application of the model is to develop scenarios for how California's energy system could potentially evolve over the next several decades, in light of strong policies to reduce energy use and greenhouse gas emissions. The scenarios range from a business-as-usual Reference Case to a Deep GHG Reduction Scenario, in which a mixed-strategy, portfolio approach allows California economy-wide emissions to be reduced 80% below 1990 levels by 2050. Several variants of the Deep GHG scenario are then also developed, in order to explore important sensitivities related to the stringency of the emissions cap (i.e., less stringent than an 80% reduction) and the ultimate potential of key resources and technologies to contribute to greenhouse gas mitigation (e.g., sustainable biomass supply, nuclear power, carbon capture and storage, and electricity and hydrogen as transportation fuels).

In sum, this analysis shows that deep, economy-wide reductions on the order of 50% to 80% appear to be technically feasible at reasonable costs (e.g., 1.0% to 2.7% of California Gross State Product over the 2005-2055 time period, relative to the baseline scenario – considering only the transportation, electricity, and fuel conversion sectors). Policy cost estimates of this magnitude are in line with those of other studies for decarbonization of the U.S. and global energy systems (IEA, 2010; NRC, 2010). The bulk of the costs would be incurred in the medium to long term (between 2025 and 2050), as increasingly advanced technologies are used to make deeper and deeper reductions. The challenge for policy, however, is perhaps the next ten years (2010-2020). This analysis shows that whether policymakers ultimately decide to pursue a reduction target of 80% or something much less stringent (say, 50%), the types of technologies that need to be introduced in the near term are for the most part the same; hence, the emissions trajectories up to 2025 would be fairly similar. Furthermore, results of this study indicate that California's current target for 2020 – the AB32 goal of bringing emissions back down to 1990 levels – may not be stringent enough. To allow time for significant market penetration of the kinds of transformational technologies that will be needed in the long term (due to the inertia of energy system infrastructure and investments), advanced technologies must be introduced over the next ten years at a quicker rate than what the existing 2020 target is likely to motivate. More specifically, over the coming decade a significant expansion in, or at least the introduction of, the following mitigation options are likely needed: renewable electricity generation, specifically from wind, solar, and geothermal resources; advanced transportation technologies and fuels, including biofuels, hybrid-electric vehicles, plug-in hybrid electric vehicles, battery-electric vehicles, and hydrogen fuel cell vehicles; and a shift toward greater utilization of electricity as an end-use fuel in the industrial, commercial, residential, and agricultural sectors. Demand reduction is also likely to play an invaluable role in mitigating future emissions, both through energy efficiency and conservation efforts and reduced vehicle travel. The latter, which could be achieved by strong transit, land use, and auto pricing policies, deserves a considerably more attention in the development of energy and climate scenarios for California.

In terms of decarbonizing California's energy system, the transportation sector poses perhaps the biggest challenge and is therefore the most costly. Over half of the state's GHG emissions are attributable to transport at present, resulting primarily from the combustion of fossil fuels (gasoline, diesel, jet fuel, and residual fuel oil). Of course, because fossil fuels are relied upon so heavily, the potential for reducing transport GHGs via alternative fuel and vehicle technologies is quite huge. Biofuels are the most cost-effective option for making these emission cuts, both from the perspective of a single vehicle or when viewed at the energy systems level, the latter including fuel production and distribution infrastructure and considering competition for biomass from other sectors, such as electric generation and industry. The challenge with biomass is that total resources, while renewable on an annual basis, are actually rather limited. Only if California were to have access to biomass supplies far beyond its "fair share" of the national or global total (e.g., >30% of all U.S. consumption), would the state be able to fuel its entire transport sector with biofuels. This is perhaps unlikely in a future where other U.S. states and countries are also counting on biomass/biofuels to mitigate their

GHG emissions. Given constraints on biomass resources, the results of this analysis indicate that the most optimal use of biofuels is in the non-light duty subsectors, namely in the form of bio-derived gasoline, diesel, jet fuel, and residual fuel oil. The reason for this is fairly intuitive: there are fewer alternative technological/fuel options to reduce GHG emissions in these other transport subsectors, hence the value of a tonne of biomass is higher. In fact, a marked advantage of light-duty vehicles is that there are quite a few alternatives for technology- and fuel-switching. Specifically, electric-drive vehicles could feasibly be used to satisfy a large portion of total VMT demand, whereas electricity and/or hydrogen are simply not realistic alternatives in some of the other subsectors, due to range limitations and refueling issues. The GHG reduction scenarios developed here rely heavily on HEVs and PHEVs (Gasoline and E-85), as well as Hydrogen FCVs to some extent, to make deep emission cuts in the light-duty subsector. In contrast, BEVs do not penetrate the LDV market to any significant degree, a result that may have more to do with model dynamics than anything else. BEVs are not favored by the model because of the various inputs that are currently assumed for the efficiencies and costs of vehicles and plug-in recharging infrastructure. The assumed costs for BEVs, for instance, are higher than for other advanced vehicle technologies because, in an effort to be fair, all vehicles in CA-TIMES are assumed to have roughly the same size, weight, range, power, etc. While this aggregated level of vehicle class representation for the most part makes sense within the modeling framework, it potentially disadvantages BEVs, which may be particularly well suited to the small car and small light truck markets or to urban driving, where travel distances are shorter. The current version of CA-TIMES is not able to capture this possibility, though future work may attempt to address this issue.

As the transport sector is decarbonized, emissions from the energy supply/conversion sector are likely to be reduced significantly as well, since the types of facilities that produce low-carbon transport fuels (e.g., bio-refineries, FT syn-fuels poly-generation plants, hydrogen plants, zero- and low-carbon electricity generation) tend to emit low levels of greenhouse gases, or at least they would in a low-carbon future. The exact carbon signature of these fuels, of course, depends on which energy resources are used for generating heat and electricity at these plants, and also whether or not carbon capture and storage is utilized. Bio-CCS technologies appear to be an especially attractive means by which to decarbonize the energy system, since they allow for negative emissions (i.e., permanently storing biomass carbon underground). In the scenarios developed in this study, bio-CCS play a major role in reducing GHG emissions while at the same time taking the burden off of other sectors, namely transport, which have higher abatement costs. When bio-CCS technologies are eliminated from the potential technology portfolio, however, the transport sector is forced to decarbonize much more significantly, and in the light-duty sector in particular, more advanced electric-drive vehicles (PHEVs and Hydrogen FCVs) become a preferred option for making these emissions cuts.

Emissions from the industrial, commercial, residential, and agricultural (ICRA) end-use sectors are reduced in this study through energy efficiency and fuel switching. In particular, drawing on other scenario studies by the IEA (2010), the Deep GHG Reduction Scenario assumes that an increasing share of energy demand is met by electricity and natural gas in the ICRA sectors in the future. How authentic these emission reductions actually are depends in large part on the simultaneous decarbonization of the electric sector, which also appears to be a likely outcome of stringent climate policy, as found in this and numerous other studies.

Comparatively, reducing emissions from electric generation is fairly straightforward and can be done at abatement costs that are lower than in the transport and energy supply sectors (IEA, 2010). Nonetheless, significant hurdles still remain, particularly with respect to spatial and temporal issues. For example, it could potentially be quite expensive to tap solar, wind, and geothermal resources in distant out-of-state locations, owing to the substantial capital investments required for long-distance transmission lines. In addition, it is still not entirely clear whether intermittent renewables, especially solar and wind, can be relied upon to contribute a majority share of total electric generation, unless significant storage and/or back-up capacity is built as well. For these reasons, the availability of nuclear power and fossil and/or biomass CCS is critical, so that low-carbon options for baseload generation remain in play. If nuclear and CCS are wholly absent from the technology portfolio, as one variant of the Deep GHG Reduction Scenario illustrates, then it will likely become considerably more difficult, and indeed more costly, to achieve a deep reduction target, if it is even possible. Other scenario variants lead to similar conclusions when biomass resources are significantly constrained or when the potential for electricity and hydrogen to be used in the transport sector is considerably limited.

An important caveat to this analysis is that it only does a partial economic accounting. In other words, it attempts to capture the total energy system *costs* of climate mitigation but largely ignores the significant economic *benefits* of pursuing this goal. For instance, the analysis does not consider the avoided costs (i.e., benefits) of climate change (e.g., more frequent extreme weather events, impacts on global agriculture and food production) or of climate adaptation (e.g., construction of sea walls, relocation of coastal populations). Similarly, the benefits accruing from reduced health expenditures and increased life expectancies, to the extent they can attributed to climate mitigation, have not been monetized here. Given this partial accounting, it is highly likely that the cost figures shown in this chapter are somewhat overestimated, a practice that is a known issue with integrated assessment models used to inform energy and climate policymaking (Nemet et al., 2010).

## Chapter III

The third chapter of this dissertation attempts to illuminate some of the key synergies, and to a lesser extent the trade-offs, between climate mitigation, energy security, air pollution and human health, and affordability, highlighting the main results and findings from an analysis that was conducted with researchers at the International Institute for Applied Systems Analysis (IIASA) in support of the Global Energy Assessment (GEA, 2011). To this end, two tools are jointly utilized in this study: a systems engineering global energy model (MESSAGE) and a global climate model (MAGICC). In sum, a wide array of plausible energy futures are generated and analyzed, in order to understand the potential evolution of the global energy system, and the subsequent climate system response, over the twenty-first century, under varying assumptions for energy security, air pollution, and greenhouse gas emissions. Each of these scenarios looks different, in both its inputs and outputs, and on a sliding scale of satisfaction, each meets the different energy system objectives to varying degrees.

This work is predicated on the notion that the energy system of the future could potentially develop along a number of different paths, depending on how society and its decision makers prioritize various, worthwhile energy objectives. These objectives are generally discussed in the context of different timeframes (e.g., security and pollution/health in the near term; climate in the medium to long term). Therefore, they frequently compete for attention in the policy world. An added challenge is that in many countries separate policy institutions are often responsible for dealing with the multiple objectives. As a result, important synergies between them are either overlooked or simply not understood, and the costs of reaching each objective individually are often overstated. By taking a more holistic and integrated perspective, we find that the synergies between the society's various energy objectives far outweigh the trade-offs.

A commonly discussed long-term goal for climate mitigation is the so-called "2 ºC target" – i.e., staying below 2 ºC maximum temperature rise, relative to pre-industrial levels, throughout the twenty-first century – which is thought to be needed to avoid dangerous interference with the climate system (Solomon et al., 2007). Maximizing the likelihood of achieving the 2 ºC target depends, above all, on making deep reductions in greenhouse gas emissions over the next several decades, a feat that will be principally accomplished by dramatically scaling up the utilization of zero-carbon energy technologies (nuclear, biomass, and other renewables) in the global energy mix. Specifically, meeting the 2 ºC target with greater than 50% probability in the long term requires zero-carbon energy shares (relative to total global primary energy supply) that are 25% or higher in the near term (2030). Furthermore, because it is pollution-free and can be derived from a variety of sources, zero-carbon energy also has the potential to significantly decrease air pollution and its corresponding health impacts, as well as improve security through supply diversification and reduced import dependence. For example, results of this analysis show that near-term targets for pollution reduction – both globally and in key developing world regions where air pollution and its health impacts are strongest – can be achieved just as effectively through decarbonization as they can through more stringent pollution control measures that are enacted in the absence of climate policy. The main pollution-climate trade-off centers around the small, but non-trivial, impact that lower levels of air pollutant emissions, namely climate-cooling aerosols (e.g., $SO_2$ and organic carbon), could have on the radiative forcing balance of the Earth. For a constant level of GHG emissions, stringent pollution control policies could potentially increase global temperatures by a few tenths of a degree, consequently lowering the probability of staying below 2 ºC maximum temperature rise by several percentage points. In terms of security benefits, substitution of domestically produced renewables (biomass, hydro, wind, solar, and geothermal) for imports of globally traded fossil commodities (coal, oil, and natural gas) could simultaneously reduce import dependence and diversify the energy resource mix away from one that relies too heavily on fossil energy.

Viewed from an holistic and integrated perspective, the combined costs of climate mitigation, energy security, and air pollution control come at a significantly reduced total energy bill if the multiple benefits of each are properly accounted for in the calculation of total energy *system* costs (i.e., when taking a systems view of the problem). For instance, our findings show that the total added costs of pollution control are cut significantly as the stringency of climate policy increases and the utilization of zero-carbon, pollution-free (hence, pollution control-free) technologies rises. In fact, pollution control cost reductions of greater than 80% are possible in the most stringent climate scenarios. Similarly, security costs also substantially decrease under increasingly aggressive levels of decarbonization. And in scenarios with extremely stringent climate policies, the added costs of security actually approach zero. While steps taken to mitigate the climate will necessarily add to total energy system costs compared to a baseline scenario, these climate costs will be substantially compensated for by the corresponding pollution control and energy security cost reductions.

# PART ONE

## Introduction

The energy challenges facing society are as varied as they are great, and for this reason energy has become a key area to address in the twenty-first century. Central among these concerns is the specter of global climate change. The impact of energy production and consumption on the earth's climate system has been well documented, and scientific studies now suggest that annual greenhouse gas (GHG) emissions must be cut 50 to 80 per cent worldwide by 2050 in order to stabilize the climate and avoid the most destructive impacts of climate change (IPCC, 2007). Toward this goal, several governments have adopted emissions targets for 2050 (in many cases, they are still aspirational targets), including Germany, Australia, the UK, the European Union, and the state of California. The United States currently has no laws specifically designed to cut GHG emissions, but momentum is growing at both the national and state levels (Litz, 2008; Lutsey and Sperling, 2008; Pew, 2009). In fact, several climate change bills have been proposed in the US Congress over the past several years to set up a domestic emissions trading program with a declining cap on annual GHG emissions that would ultimately lead to economy-wide reductions in the range of 50-80% by 2050.[1,2] Climate change has also become a core issue at the international level. In 2009, for instance, the Group of Eight (G8) industrialized nations agreed to reduce global GHG emissions 50% below 1990 levels by 2050, with the intent to hold global warming to less than 2 degrees Celsius above pre-industrial levels (G8, 2009). The Copenhagen Accord later adopted

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[1] An 80% reduction in annual US GHG emissions (from all sources) below 1990 levels is equivalent to an 83% reduction below 2005. Annual GHGs in 1990 were 14% lower than in 2005 [EPA, 2008b. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. Environmental Protection Agency, Washington, DC.].

[2] "Comparison of Legislative Climate Change Targets," World Resources Institute (http://www.wri.org/publication/usclimatetargets) and (http://www.wri.org/chart/comparison-legislative-climate-change-targets-110th-congress-1990-2050)

the 2º C target. Here in California, *global* climate change could have a pronounced *local* impact, affecting the state's economy, natural and managed ecosystems, and human health and mortality (California Department of Environmental Protection, 2006).

Yet, despite the growing consensus for the need to reduce greenhouse gas emissions, the strategies for meeting these ambitious targets have not been clearly defined, and the technology and policy options are not well enough understood. For years, scenario analyses and energy modeling tools have been used widely to envision the potential evolution of energy systems over time. Until more recently, however, very few studies, had done detailed analyses of how *deep* cuts in greenhouse gas emissions could be made across all energy sectors in the long-term, using commercial or near-commercial low-carbon and advanced technologies and fuels. In particular, the literature lacked analyses focusing specifically on making deep cuts in transport sector emissions, whether in California or the United States or at the global level.

A large number of studies have investigated different aspects of making transport sector GHG reductions, but very few have simultaneously included all transport subsectors in their analyses or have looked at scenarios for making deep emissions cuts. (At least this was true at the start of this dissertation project.) Most scenario analyses (e.g., (Bandivadekar et al., 2008; Grimes-Casey et al., 2009; Mui et al., 2007; NRC, 2008; Yeh et al., 2008)) concentrate only on light-duty vehicles (LDV) since they make up such a large share (60%) of US transport GHGs, whereas the few studies that do include additional on- and non-road subsectors (e.g., (IEA, 2008; WBCSD, 2004)) concentrate their analyses at the global level, meaning one cannot easily use them to assess the evolution of national and sub-national transportation systems, such as those in California and the US. Similarly, while several studies have looked at slight to moderate reductions from the LDV subsector (e.g., (Bandivadekar et al., 2008; Mui et al., 2007)), very few consider the feasibility of making deep carbon cuts in the long-term. For example, WBCSD (2004) develops a scenario that combines multiple GHG mitigation strategies in order to bring global annual road vehicle emissions back down to 2000 levels by 2050. In addition, a recent report by the National Research Council develops a "Hydrogen Success" scenario, in which LDV emissions are reduced 50% below 2005 levels by 2050, as well as a portfolio scenario, in which advanced biofuels and high efficiency internal combustion engine vehicles also achieve significant penetration, helping to reduce GHGs even further (85%).

Over the past two years, as energy and climate change have become even more prominent concerns, researchers and analysts have started to fill the void in the literature discussed above. In fact, some of the first major research in this area has been carried out by myself and colleagues in the STEPS Program at UC Davis – e.g., see the "80in50"studies by Yang, McCollum et al. (2009) and McCollum and Yang (2009), who analyzed scenarios for making deep cuts in emissions across all transport subsectors in California and the US, respectively. The US-focused *80in50* analysis is the subject of the first chapter of this dissertation.

As discussed in Section I, the *80in50* studies investigate the potential for reducing transport GHG emissions 50-80% below 1990 levels by 2050. Scenarios are used to envision how such a significant decarbonization might be achieved through the application of advanced vehicle technologies and fuels, and various options for behavioral change. In contrast to most previous studies, a relatively simple, easily adaptable modeling methodology is developed, which can incorporate insights from other modeling studies and organize them in a way that is easy for policymakers to understand. Also, a wider range of transportation subsectors is considered than in other studies—e.g., light and heavy duty vehicles, aviation, rail, marine, agriculture, off-road, and construction. The analysis investigates scenarios with multiple emissions reduction options (increased efficiency, lower-carbon fuels, and travel demand management) across the various subsectors. In support of this effort, two Excel-based spreadsheet modeling tools have been developed, which quantify the emission reductions potential of the various GHG mitigation strategies in the California and US transportation sectors.[3] One version of this so-called Long-term Evaluation of Vehicle Emission Reduction Strategies (LEVERS) model was tailored to California while another one focused on the entire U.S. The analytical framework of these models relies on decomposing total GHG emissions into four main drivers (population, travel demand, vehicle fuel consumption, and fuel carbon intensity) and expressing emissions as a product of those drivers. In particular, a transport-variant of the Kaya identity is used to do the decomposition analysis (Kaya, 1990). Note that several other studies have utilized similar decomposition approaches in

[3] Note that the *80in50* research project originally started out as an analysis for California, but was eventually expanded to take on a US focus, as was the LEVERS model. My role in this research was the following: (1) in the California *80in50* project, I was the lead graduate student researcher under the supervision of Dr. Christopher Yang; and (2) in the US *80in50* project, I was the lead project investigator, working closely with Dr. Yang on the analysis.

recent years to study historical energy use and GHG emissions (Ang and Zhang, 2000; Lakshmanan and Han, 1997; Mui et al., 2007; Schipper et al., 2001; Scholl et al., 1996).

While the *80in50* studies were successful in answering the types of research questions they were intended for, like any research project they had several important limitations. Hence, to start to address these shortcomings and to further push our scenario analysis capabilities, our research group at UC-Davis undertook the development of an energy-engineering-environmental-economic systems optimization model. This type of work represents yet another method for developing energy scenarios. Well-known examples of such models include the US Energy Information Administration's NEMS model, the US Environmental Protection Agency's nine-region MARKet ALlocation (MARKAL) model for the United States, and the International Energy Agency's global MARKAL model. Each of these is capable of analyzing all transport subsectors simultaneously along with all other components of the energy system. However, until recently, none had been utilized to study in detail how deep emission reductions could be made in the long-term from all energy sectors, and in particular from all transport subsectors (e.g., see (Gallagher and Collantes, 2008)). Another problem with these models, at least for the purposes of this dissertation, is that because they are so broad in their geographic scope (in general, this is a good thing), they are not really conducive to carrying out California-specific analyses.

As described in Section II, for a large part of my dissertation work, I have developed an early version of the CA-TIMES energy systems optimization model. In sum, CA-TIMES is a technologically-rich, energy systems model for California, along the lines of those models developed and maintained by the EIA, IEA, and EPA. It is a variant of the MARKAL and TIMES family of energy models, which focuses on the California energy system and contains California-specific data and assumptions. CA-TIMES represents a unique simulation tool in that it is the first publicly available model of its kind in the state. Other types of economic models have previously been used for near-term (2020) energy and climate policy analysis in California, for example, the Energy 2020 model by Systematic Solutions; an electricity and natural gas sector model by Energy and Environmental Economics (E3); and the Environmental Revenue Dynamic Assessment Model (E-DRAM) by UC-Berkeley, California Department of Finance, and California Air Resources Board. However, CA-TIMES is different from some or all of these models in that contains richer, bottom-up technological detail, covers all sectors of the California energy economy, is primarily focused on the medium to long term (2020-2050), and resides in the public domain. As California moves forward with a broad spectrum of carbon emissions reduction policies, there is a strong need for this kind of transparent, flexible, and accessible analysis tool to help inform policy decisions. My dissertation work begins this process by performing scenario analyses, evaluating policy, and presenting technological portraits for the future given the specific conditions that exist within the state. In this way, it fills an important void in the literature and research community, specifically in California. In addition, the CA-TIMES energy systems modeling project addresses some of the limitations of the *80in50* research by further expanding the scope of the analysis. First, since the CA-TIMES model is an energy-engineering-environmental-*economic* systems optimization model, it brings costs and prices into the analysis as decision variables. This means future technology-fuel combinations are selected endogenously by the model, rather than exogenously, as is done in the original *80in50* research. Second, whereas the *80in50* research looks at scenario “snapshots” in the year 2050, my analyses with CA-TIMES look at the transition pathway from now to 2050, allowing me to focus on important milestone years for policy (e.g., 2020). Third, all energy producing and consuming sectors are represented in the CA-TIMES *systems* model, as opposed to representation of only the transport sector. This permits an improved understanding of the potential responses of the entire energy system to a suite of energy and climate policies, since cross-sector linkages are accounted for. As an example, competition for limited primary energy resources can be more accurately modeled under the CA-TIMES framework (e.g., biomass for transportation fuels vs. biomass for electricity production).

The main objective in creating a MARKAL-TIMES model for California is to develop and analyze scenarios for meeting future energy and emissions reduction goals, with an eye toward the transportation, electricity, and energy supply and conversion sectors. In other words, this research is a direct extension of my *80in50* work, though a bit more complex and comprehensive in nature. The aim is to provide insights on how economic drivers, such as cost considerations and an emissions trading program, and policies, like a renewable portfolio standard (RPS) for electricity, biofuels mandates, and vehicle tailpipe emissions standards, might affect future decisions on the investment of future energy technologies and utilization of resources under various scenarios.

The CA-TIMES research builds on several previous studies that have used a bottom-up energy systems optimization model approach for developing transportation scenarios. These include Schäfer and Jacoby (2006), IEA (2008), IEA (2010), and Yeh et al. (2008). For example, Schäfer and Jacoby (2006) combine MARKAL with a computable general equilibrium model and a modal split model in order to estimate the impact of advanced vehicle technologies on GHGs. They conclude that given an economy-wide reduction target, advanced vehicles will not be utilized in large numbers until gasoline prices rise to extremely high levels (US$9.50/gal, or $2.50/L). Similarly, Yeh et al. (2008) also find that, under an economy-wide target and because of relatively high marginal abatement costs, the transport sector will likely not contribute significantly to GHG reductions until less expensive mitigation options in other sectors (such as electricity production) have first been exhausted and the prevailing price of $CO_2$ has risen substantially. Moreover, the IEA's Energy Technology Perspectives (ETP) studies show that if deep (50-80%) economy-wide reductions are to be made in the long-term, all sectors of the energy system will eventually need to be significantly decarbonized. IEA finds that making deep reductions in global emissions will require an energy revolution, and they have estimated that in an optimistic case (their BLUE Map scenario), reducing global annual GHG emissions 50% below 2005 levels by 2050 (requiring 80% reductions in the U.S. and other industrialized countries) would involve the utilization of technologies with marginal abatement costs up to about $200/tonne $CO_2$. The IEA ETP studies show that if deep GHG reductions are to be made in the long term, the transport sector, which accounts for a significant 23% of global GHG emissions at present – in the US the corresponding figure is 29%, and in California 40% (CARB, 2008a; EPA, 2006; ITF, 2008) – will have to play a major role. Their analyses show, in particular, that the most important mitigation strategies are likely to be improved vehicle efficiencies, biofuels, and advanced technologies such as hydrogen and electric vehicles.

# RESEARCH STREAM #1

## I. Achieving deep reductions in US transport greenhouse gas emissions: Scenario analysis and policy implications (80in50)

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**Abstract:**

This chapter investigates the potential for making deep cuts in US transportation greenhouse gas (GHG) emissions in the long-term (50-80% below 1990 levels by 2050). Scenarios are used to envision how such a significant decarbonization might be achieved through the application of advanced vehicle technologies and fuels, and various options for behavioral change. A Kaya framework that decomposes GHG emissions into the product of four major drivers is used to analyze emissions and mitigation options. In contrast to most previous studies, a relatively simple, easily adaptable modeling methodology is used which can incorporate insights from other modeling studies and organize them in a way that is easy for policymakers to understand. Also, a wider range of transportation subsectors is considered here—light and heavy duty vehicles, aviation, rail, marine, agriculture, off-road, and construction. This analysis investigates scenarios with multiple options (increased efficiency, lower-carbon fuels, and travel demand management) across the various subsectors and confirms the notion that there are no

"silver bullet" strategies for making deep cuts in transport GHGs. If substantial emission reductions are to be made, considerable action is needed on all fronts, and no subsectors can be ignored. Light duty vehicles offer the greatest potential for emission reductions; however, while deep reductions in other subsectors are also possible, there are more limitations in the types of fuels and propulsion systems that can be used. In all cases travel demand management strategies are critical; deep emission cuts will not likely be possible without slowing growth in travel demand across all modes. Even though these scenarios represent only a small subset of the potential futures in which deep reductions might be achieved, they provide a sense of the magnitude of changes required in our transportation system and the need for early and aggressive action if long-term targets are to be met.

[*] Note: The text of this chapter is primarily derived from an *Energy Policy* paper that was published by me and Chris Yang in 2009. Therefore, in some places the "voice" may sound more like that of a journal article. (For the full paper, see the following reference: McCollum, David L. and Christopher Yang (2009) Achieving Deep Reductions in U.S. Transport Greenhouse Gas Emissions: Scenario Analysis and Policy Implications. *Energy Policy* 37 (12), 5580 – 5596.)

### I.1 Historical Energy Use and Emissions in the US Transport Sector

In this chapter, *Domestic* GHG emissions include those emissions generated from trips taking place entirely within the US—i.e., from a US origin to a US destination. *Overall* emissions attempt to include half of all emissions generated from trips with either an origin or destination in the US, which captures emissions generated as a result of US passenger and goods transport abroad. In particular, *Overall* emissions include international aviation and marine travel where an airplane or ship leaves (or arrives from) the U.S. for (or from) points abroad. Thus, the aviation and marine subsectors account for a larger share of *Overall* emissions than they do of *Domestic* emissions. We estimate total *Domestic* well-to-wheel emissions from US transportation in 1990 were approximately 1,921 million metric tonnes $CO_2$e (MMT$CO_2$e).[4] *Overall* emissions were 2,104 MMT$CO_2$e. Note that these figures are higher than those reported elsewhere (e.g., in EPA (2006)) for US on- and off-road mobile source emissions because our estimates are lifecycle emissions while others may only report end-use emissions generated from fuel combustion onboard the vehicle.

Table 1 gives a breakdown of transportation energy use and lifecycle GHG emissions by subsector in the US in 1990 for both the *Domestic* and *Overall* cases. Light-duty cars and trucks (passenger cars, pickup trucks, SUVs, minivans, and motorcycles) were responsible for about 60% of *Domestic* GHG emissions. Heavy-duty vehicles (large trucks and buses) accounted for another 17%. Domestic aviation (including commercial

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[4] MMT = million metric tonnes; $CO_2$e includes $CO_2$, $CH_4$, and $N_2O$ weighted by their respective global warming potentials (100-year timeframe). The terms $CO_2$ and greenhouse gases are used interchangeably in this paper, as calculations are based upon equivalent carbon dioxide emissions ($CO_2$e) using global warming potential of different GHGs.

(passenger), freight, and general aviation) comprised 11% of emissions, and the remaining 12% was from a combination of rail, domestic marine, agriculture, and off-road equipment. The breakdown of energy use by subsector is very similar to that for GHG emissions because of the overwhelming reliance on various forms of petroleum fuels, which all have similar carbon intensity values.

Aviation emissions shown here only account for the six GHGs included in the Kyoto Protocol, and in particular $CO_2$, $CH_4$, and $N_2O$, though emissions of $NO_x$, $SO_x$, $H_2O$, and soot (i.e., non-$CO_2$ aviation emissions) also impact the climate when released in the upper atmosphere (IPCC, 1999). The radiative forcing associated with these emissions is influenced by their short persistence in the atmosphere (hours to days) (Forster et al., 2006). To account for the additional climate impacts that non-$CO_2$ emissions may cause, some have proposed multipliers (‘uplift factors’) for converting a given quantity of non-$CO_2$ emissions into the standard $CO_2$-equivalent metric (Macintosh and Wallace, 2009). Current estimates lie in the range of 1.5-4.0, though considerable uncertainty still remains (Forster et al., 2007; Marbaix et al., 2008)}.

**Table 1 Transportation Energy Use and Lifecycle Emissions by Subsector in the US in 1990 (Based on authors’ calculations using data from numerous sources)**

| | | **Energy Use** | | | | **GHG Emissions*** | | | |
|---|---|---|---|---|---|---|---|---|---|
| **Subsector** | **Vehicle Type** | **Domestic** | | **Overall** | | **Domestic** | | **Overall** | |
| | | **(PJ)** | **%** | **(PJ)** | **%** | **MMT $CO_2$e** | **%** | **MMT $CO_2$e** | **%** |
| Light-duty | Cars & Trucks | 12,603 | 60.1% | 12,603 | 54.8% | 1,159 | 60.3% | 1,159 | 55.1% |
| Heavy-duty | Buses | 176 | 0.8% | 176 | 0.8% | 16 | 0.8% | 16 | 0.8% |
| | Heavy Trucks | 3,370 | 16.1% | 3,370 | 14.7% | 304 | 15.8% | 304 | 14.5% |
| Aviation | Commercial (Passenger) | 1,779 | 8.5% | 2,335 | 10.2% | 160 | 8.3% | 210 | 10.0% |
| | Freight | 365 | 1.7% | 555 | 2.4% | 33 | 1.7% | 50 | 2.4% |

| | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|
| | General | 139 | 0.7% | 139 | 0.6% | 13 | 0.7% | 13 | 0.6% |
| Rail | Passenger | 77 | 0.4% | 77 | 0.3% | 14 | 0.7% | 14 | 0.6% |
| | Freight | 458 | 2.2% | 458 | 2.0% | 41 | 2.1% | 41 | 2.0% |
| Marine | Large Marine – Intl. | - | 0.0% | 1,278 | 5.6% | - | 0.0% | 115 | 5.5% |
| | Large Marine – Domestic | 341 | 1.6% | 341 | 1.5% | 31 | 1.6% | 31 | 1.5% |
| | Personal Boats | 197 | 0.9% | 197 | 0.9% | 18 | 0.9% | 18 | 0.9% |
| Agriculture | Agriculture | 444 | 2.1% | 444 | 1.9% | 40 | 2.1% | 40 | 1.9% |
| Off-road | Off-road | 1,017 | 4.9% | 1,017 | 4.4% | 92 | 4.8% | 92 | 4.4% |
| **Total – All subsectors** | | **20,966** | | **22,990** | | **1,921** | | **2,104** | |

* Emissions estimates reported here are higher than those from other published studies because we include the GHGs produced during upstream ("well-to-tank") fuel production processes.

## I.2 Methodology

This analysis builds upon previous work completed by UC-Davis researchers, which looked at how the US state of California might reduce its transport sector GHGs (Yang et al., 2009). For that analysis, the Long-term Evaluation of Vehicle Emission Reduction Strategies (LEVERS) model was developed to quantify the emission reductions potential of the various GHG mitigation strategies in California's transportation sector. The scope of the LEVERS model has since been expanded to conduct US-focused analyses.[5] The analytical framework relies on decomposing total GHG emissions into a handful of key drivers and expressing emissions as a product of those drivers. Decomposition analysis has become a popular energy and environmental analysis tool in recent years (Ang and Zhang, 2000; Schipper et al., 2001), and several studies have used decomposition analysis to study historical energy use and GHG emissions in US transport by subsector (Lakshmanan and Han, 1997; Mui et al., 2007; Scholl et al., 1996).

[5] For an expanded description of the LEVERS model and all input assumptions, the interested reader is encouraged to see the appendix to the published *Energy Policy* paper, on which this chapter is based. (McCollum, David L. and Christopher Yang (2009) Achieving Deep Reductions in U.S. Transport Greenhouse Gas Emissions: Scenario Analysis and Policy Implications. *Energy Policy* 37 (12), 5580 – 5596.)

In this analysis, a transport-variant of the Kaya identity is used (Kaya, 1990), which decomposes transportation $CO_2$e emissions into four main drivers: population, travel demand, vehicle fuel consumption, and fuel carbon intensity. This Kaya equation is developed for each transport subsector and vehicle type and is summed over these categories to obtain emissions for the entire transport sector (see equations 1, 2). Yang et al. (2008) and Yang et al. (2009) describe this framework in more detail.

$$CO_2 \equiv (Population)\left(\frac{Transport}{Person}\right)\left(\frac{Energy}{Transport}\right)\left(\frac{Carbon}{Energy}\right) = P \times T \times E \times C \qquad (1)$$

$$CO_{2,Transport} \equiv \sum_i \sum_j CO_{2,i,j} \equiv \sum_i \sum_j P \times T_{i,j} \times E_{i,j} \times C_{i,j} \qquad (2)$$

where $i$ = subsector, $j$ = vehicle type

Population (P) and transport intensity (T) are the societal, or activity, parameters. Both of these terms are projected to increase substantially by 2050 under business-as-usual conditions. The latter two parameters in the identity are technological in nature: energy intensity (E) describes the energy use per-mile (e.g., MJ/mile) of transport, and carbon intensity (C) describes the carbon emissions per unit of energy (e.g., $gCO_2e/MJ_{LHV}$)[6]. Together they define the amount of carbon emitted per-mile of transport. The T, E, and C parameters represent the three main “levers” for reducing transport GHG emissions. In this analysis, population is not considered as a potential lever. In all scenarios, the US

[6] In this chapter, the carbon intensity values are shown on a lower heating value (LHV) basis, whereas in the next chapter on the CA-TIMES work, they are shown on a higher heating value (HHV) basis. Most studies report carbon intensities in terms of LHVs, as they represent the actual quantity of emissions associated with the amount of useable energy contained in a given quantity of fuel (minus the latent heat of vaporization of $H_2O$, since the energy contained in water vapor generally ends up as waste heat on-board a vehicle).

population is assumed to increase 69% from 248.7 million in 1990 to 419.9 million in 2050 (U.S. Census Bureau, 2008a, b).

Our study is informed by numerous other studies and reports found in the literature, which discuss the various strategies available for mitigating emissions in the different transport subsectors by pulling the transport, energy, and carbon intensity levers (e.g., (An and Santini, 2004; Ang-Olson and Schroeer, 2003; Arthur D. Little, 2002; CARB, 2004; Cowart, 2008a; EUCAR, 2007; Eyring et al., 2005; Frey, 2007; Greene and Schafer, 2003; Greszler, 2007; IEA, 2008; IUR, 2008; Kahn Ribeiro et al., 2007; Kasseris and Heywood, 2007; Kromer and Heywood, 2007b; Marintek, 2000; O'Connor, 2007a; Rodier, 2009; Weiss, 2000; Yang et al., 2008)). In this study, we do not explicitly model the economics (e.g., costs and benefits) and dynamics (e.g., interactions, timing and transition issues) associated with specific mitigation options, although other studies addressing these issues have informed our judgments as to what is plausible in the 2050 timeframe, with respect to technology, economics, consumer acceptance, and structural and behavioral change. The mitigation options described in these numerous studies for the various transport subsectors (e.g., possible changes in vehicle efficiency, low-carbon fuel options and availability and potential for travel demand reduction) were combined using the LEVERS model in order to construct the various scenarios that make up this analysis.

Lifecycle fuel carbon intensity assumptions in our analysis are taken from the Greenhouse gas Regulated Emissions and Energy Use in Transportation (GREET) model developed by Argonne National Laboratory (Wang, 2007). While a number of alternative lifecycle analysis models and studies exist and while there is some controversy over which best represents reality (e.g., (Delucchi, 2003; JRC/IES, 2008; Tilman et al., 2006)), we ultimately chose GREET because it is comprehensive in its coverage of fuels, has a US focus, and is relatively transparent, publicly available, and widely used by transportation-energy researchers. It is also likely to be familiar to the intended audience of this paper. Like any lifecycle analysis (LCA) model, GREET has its strengths and weaknesses and involves many debatable assumptions, all of which have been inherited into our analysis as well.

As in other recent scenario analyses (Grimes-Casey et al., 2009; Olabisi et al., 2009), we use lifecycle emissions instead of end-use emissions because we are only focusing on one specific sector, transport. The opposite approach would ignore the spillover effects of the transport sector in other sectors (e.g., agricultural, electricity, fuel production) in terms of upstream emissions, which would distort the analysis by giving one a false picture of which mitigation options are preferred, especially those which have low end-use emissions (e.g., hydrogen and electricity) but whose production-related upstream emissions can vary widely. This approach is necessary, since a major goal of this study is to envision how significant decarbonization of the transport sector might be achieved based on using a variety of transport sector strategies. It is important to note that our LCA system boundary includes transportation fuel production and biomass production in the agriculture sector, but excludes vehicle manufacture and disposal.

## I.3 Results and Scenarios for 2050

Three sets of scenarios and their underlying assumptions were developed for this project and are presented and discussed below: (1) a *Reference* scenario to establish a business-as-usual baseline for comparison, (2) *Silver Bullet* scenarios to examine the potential reductions from individual solutions and (3) *50in50* and *80in50* scenarios to illustrate several mixed (i.e., portfolio) strategy approaches for reducing emissions 50-80% below 1990 levels by 2050. None of these scenarios should not be taken as predictions or forecasts of the future. Rather, they are composed of a large number of assumptions informed from other studies about what a 2050 world could potentially look like in terms of travel demand and alternative fuel and advanced vehicle technology adoption for different levels of GHG reduction.

### *I.3.1 Reference Scenario*

The *Reference* scenario describes a future where very little is done specifically to address climate change, and transportation activity and technology development follow historical trends. It is built from assumptions informed by dozens of other studies. In this business-as-usual scenario, population grows 69% from 249 million in 1990 to 420 million in 2050, and across all subsectors transport intensity (T) is expected to increase significantly (doubling, on average), with the aviation subsector seeing the largest relative growth (Table 2). Vehicle load factors (passengers/vehicle) are assumed to be the same as in 1990. Total travel demand (P x T) is nearly 3.4 times the 1990 value in the *Domestic* case and 4.2 times higher in the *Overall* case. These projections are based largely on the EIA's Annual Energy Outlook (AEO) 2008 Reference Case projections to 2030, which we have extended to 2050 using linear extrapolation (EIA, 2008a). Alternately, using projections from the EIA's High Price Case would bring down the expected growth in travel demand. For light-duty vehicles, the projected growth from 1990 to 2050 would be just 51%, instead of the 71% shown in Table 2. This would translate into an increase in LDV GHGs of only 24%, compared to 41%.

In the *Reference* scenario, conventional vehicles and fuels continue to be employed. In the light-duty vehicle (LDV) subsector, there is a fairly significant reduction in fleet energy intensity (47%) compared to 1990, which assumes that the average on-road fuel economy is 35 miles per gallon (mpg)—i.e., equal to the 2007 federal Corporate Average Fuel Economy (CAFE) standards (35 mpg (6.7 L/100km) tested for new vehicles in 2020).[7] For most other subsectors, average fleet energy intensities in 2050 are assumed to be slightly lower than they were in 2005. For aviation, reductions are greater. Since 1990, fleet-average energy intensities (per passenger- or ton-mile) for both commercial and freight aircraft have already declined by more than 30% (ORNL, 2008). Lee et al. (2001) estimate that if historical trends continue to persist into the future, energy intensities of new aircraft will be reduced 30-50% between 2000 and 2025 and that these levels will represent the fleet average by 2050. These significant reductions will require the widespread adoption of state-of-the-art aircraft technologies such as more efficient propulsion systems, advanced lightweight materials, and improved aerodynamics (e.g., winglets, increased wingspans), and potentially the adoption of even more advanced technologies—e.g., laminar flow control, unducted fan open-rotor engines, and improved air traffic control systems) (IEA, 2008; Lee et al., 2001; Schäfer et al., 2009).

[7] CAFE standards would have to be raised slightly beyond 35 mpg as test cycle fuel economies are typically higher than on-road values and corrected by multiplying test numbers by a factor of 0.80.

Table 2 shows that total transport sector-wide energy intensity is reduced 45% between 1990 and 2050, and the average carbon intensity of all transportation fuels is about 2% lower than in 1990. In the LDV subsector, the carbon intensity reduction is greater (9%) due to the use of low-carbon biofuels for blending in LDVs, which in 2050 is assumed to be consistent with the new Renewable Fuels Standard (RFS) targets for 2022 – approximately 24 billion gallons gasoline equivalent (gge) – and that all biofuels come from low lifecycle GHG cellulosic sources. The reduction in fuel carbon intensity from biofuels is balanced by the increased use of oil from higher carbon, unconventional sources in all subsectors.

*Domestic* (lifecycle) emissions reach 3,496 MMT$CO_2$e in 2050 (+82% from 1990) while in the *Overall* emissions case they reach 4,210 MMT$CO_2$e (+100% from 1990).

**Table 2 Change in Transport Intensity, Energy Intensity, Carbon Intensity and GHG Emissions Between 1990 and 2050 and GHG Share by Subsector in the *Reference* Scenario**

| | | LDV | HDV | Aviation | Rail | Marine / Ag / Offroad | All Subsectors |
|---|---|---|---|---|---|---|---|
| **T** | **Domestic** | +71% | +99% | +266% | +43% | +92% | +102% |
| | **Overall** | +71% | +99% | +415% | +43% | +92% | +148% |
| **E** | **Domestic** | -47% | -20% | -57% | -20% | -50% | -45% |
| | **Overall** | -47% | -20% | -57% | -20% | -50% | -44% |
| **C** | **Domestic** | -9% | +6% | +6% | -9% | +6% | -2% |
| | **Overall** | -9% | +6% | +6% | -9% | +6% | -1% |
| **GHG** | **Domestic** | +41% | +175% | +183% | +74% | +70% | +82% |
| | **Overall** | +41% | +175% | +300% | +74% | +73% | +100% |
| **GHG Share** | **Domestic** | 46.6% | 25.2% | 16.6% | 2.7% | 8.8% | --- |
| | **Overall** | 38.7% | 20.9% | 25.9% | 2.3% | 12.2% | --- |

### *I.3.2 "Silver Bullet" Scenarios*

Because of the diversity and breadth of vehicle types and functions across the transportation subsectors, individual technology or fuel options alone are unlikely to be sufficient in achieving deep reductions in emissions. This “no silver bullet” notion has become well established in recent years (e.g., (Grimes-Casey et al., 2009; WBCSD, 2004)). In order to further illustrate this insight and understand the potential reductions from individual options, we developed several *Silver Bullet (SB)* scenarios that describe futures in which one mitigation option (such as an advanced vehicle technology, alternative fuel, or travel demand management), is employed to the maximum feasible extent from a technological, economical, and behavioral perspective in 2050, based upon an extensive literature review.

These scenarios explore individual options such as efficiency, biofuels, hydrogen, electricity, and controlling vehicle miles traveled (VMT). Not surprisingly, our findings substantiate those of other studies: none of the *Silver Bullet* scenarios, even with very optimistic assumptions, are able to achieve the ambitious 50-80% reduction goal, and none even reduce GHG emissions significantly compared to 1990. These scenarios lend further support to the notion that a portfolio approach is needed to make deep GHG reductions in the transportation sector, especially when constraints on technology and resources are properly accounted for.

For an extended discussion of our *Silver Bullet* scenarios and results, including descriptions of the scenarios themselves, the interested reader is encouraged to see the online supplementary material to the original *Energy Policy* paper, on which this chapter is based.

### *I.3.3 Deep Emission Reduction Scenarios*

While there is no one silver bullet strategy for achieving the ambitious 50-80% GHG reduction goal, many of the individual options are complementary and can be combined in a portfolio approach to help reduce total transportation emissions. Three mixed-strategy scenarios were developed to explore these portfolios and understand a range of different transportation futures in which *Domestic* GHG emissions are reduced by either 50% (*50in50* scenarios) or 80% (*80in50* scenarios) below 1990 levels by 2050. The two *50in50* scenarios illustrate the two distinct primary vehicle and fuel paths to low-carbon transportation: biofuels and electric-drive. However, increasing vehicle efficiencies and decreasing per-capita VMT beyond the *Reference* scenario are important components of these scenarios as well. The *80in50* scenario combines these two main options and looks at how emissions might be reduced even further by addressing each subsector to the furthest extent possible.

The three deep emission reduction scenarios have been crafted from a set of optimistic, yet plausible, assumptions about the extent of technological and behavioral change that could be possible out to 2050. A large number of factors (vehicle and fuel technology development, economic context, resource limitations, lifestyle changes, consumer preferences, and policies) will influence what is possible and ultimately plausible in an uncertain world 40+ years into the future. While plausibility is inherently a subjective concept, to inform our scenario development, we have relied on a number of other studies which attempt to estimate plausible penetrations of advanced technology and fuel options over time.

Given the magnitude of changes required for achieving deep emissions reductions, we acknowledge that significant uncertainty and challenges exist in bringing about any single mitigation option, let alone the large and diverse suite of options that are ultimately needed. Certainly one of the key challenges in meeting the deep emissions reductions targets is associated with the rate at which options can be introduced into the transportation system. Vehicles can have very long lifetimes, and as a result, it can take decades before a new technology, especially if introduced slowly, becomes widespread throughout the vehicle fleet. New low-carbon fuel infrastructure, smart growth and better community design, and public transportation infrastructure are also key contributors to potential GHG reductions that will take a long time to implement and become widespread.

In the LDV subsector, each scenario assumes a moderate shift away from trucks and SUVs towards cars; and along with improvements in vehicle propulsion systems, this helps to push up fleet average fuel economies. For simplicity, we ignore any potential "VMT rebound effects" that might result from a shift to cars from trucks/SUVs[8] or a shift to more-efficient vehicles, since it is not clear that the same factors at play in the past will continue to persist into the future.

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[8] In recent years the average annual VMT of US cars has been greater than that of trucks/SUVs ORNL, 2008. Transportation Energy Data Book, Edition 27, in: Diegel, D.a. (Ed.). US Department of Energy, Oak Ridge National Laboratory.. However, the two vehicle classes were quite similar in the late-1990s.

The carbon intensity of electricity assumed in the three scenarios, 43.6 $gCO_2e$/MJ (157 $gCO_2e$/kWh), is approximately 80% below the 1990 level (207 $gCO_2e$/MJ), which assumes significant generation (60%) from zero-carbon resources (nuclear and renewables) and large contributions from natural gas combined cycle generators and coal plants with carbon capture and sequestration. Many other studies have shown that these technologies for decarbonizing the electricity sector are among the least expensive options for achieving significant reductions in electric sector GHG emissions and would be a major part of any attempt to make deep cuts in economy-wide GHGs (EIA, 2007, 2008b; EPA, 2007; IEA, 2008; Yeh et al., 2008). Table 3 provides representative average lifecycle carbon intensities for gasoline, electricity, biofuels, and hydrogen produced in the US. These may serve as a point of comparison for the carbon intensities of advanced fuels and energy carriers that are assumed in the scenarios discussed in this study.

Population growth is the same in each 2050 scenario as in the *Reference* scenario, growing 69% from 1990 levels.

**Table 3 Representative Average Lifecycle Carbon Intensities (C) of Fuels Produced in the U.S. (Source: (Wang, 2007))**

| **Fuels and Energy Carriers** | **Carbon Intensity ($gCO_2$/MJ)*** |
|---|---|
| **Gasoline (100%, no biofuel blended)** | 92 |
| **Electricity** | |
| Average U.S., 1990 | 207 |
| Coal, conventional boiler-steam turbine | 343 |
| Natural Gas Combined-Cycle, gas turbine | 129 |
| Natural Gas, simple cycle gas turbine | 215 |
| Nuclear | 2 |
| Renewables (solar PV and thermal, wind, geothermal, hydro) | ~0 |

| | |
|---|---|
| **Biofuels** [α] | |
| Ethanol, corn | 60 – 111 (60 – 205) |
| Ethanol, cellulosic | 5 – 20 (5 – 130) |
| Biodiesel, cellulosic | 5 – 40 (5 – 150) |
| **Hydrogen** | |
| Natural gas feedstock | 90 – 112 |

Table Notes:
* As shown by the Kaya equation in Section I.2, the product of vehicle energy intensity (E) and fuel carbon intensity (C) defines the GHG emissions per mile (or kilometer) driven, thus even though the carbon intensity of electricity may be higher than gasoline, electric vehicles will generally have much lower emissions per mile because of much higher vehicle efficiency.
[α] Base carbon intensity of biofuels depends on production method (e.g., type of biomass feedstock, coal vs. natural gas energy input, wet vs. dry distillers grains, etc.). Values in parentheses include the potential additional GHG impacts of land use change, using estimates from Searchinger et al. (2008).

*Efficient Biofuels 50in50 scenario*

The *Efficient Biofuels 50in50* scenario relies heavily on biofuels (cellulosic ethanol and biodiesel). The average lifecycle carbon intensity (12.3 $gCO_2e/MJ$) of these biofuels is very low, resulting almost entirely from biomass feedstock production, collection, and transport, and biofuels distribution (Wang, 2007). Relative to the *Reference* scenario, improved vehicle efficiencies across all subsectors and reductions in per-capita VMT growth contribute to a decrease in total transportation fuel demand and enable the US biomass resource base to supply the majority of fuel demands. All LDVs are powered by low-carbon biofuels (no gasoline is used), and in addition biofuels supply 20% of total fuel demand for buses and heavy-duty trucks. No other subsectors are able to be supplied with biofuels due to constraints on biomass feedstock availability: the upper limit of US biofuels production has been estimated at roughly 90 billion gge per annum (Perlack et al., 2005).[9] These other subsectors continue to use conventional fossil fuels, albeit in a

[9] The Natural Resources Defense Council (NRDC) puts this estimate at 120 billion gge [(NRDC, 2004. Growing Energy: How Biofuels Can Help End America's Oil Dependence. Natural Resources Defense Council.]. IEA estimates global liquid biofuels potential to be in the range of 443-536 billion gge. [IEA, 2004. Biofuels for Transport: An International Perspective. International Energy Agency, Paris, France.].

more efficient manner (total sector energy intensity declines by 63%, an 18 percentage point improvement over the modest energy intensity reductions assumed in the *Reference* scenario). Improvements in engine efficiency and vehicle hybridization enable the average fuel economy of the entire light-duty vehicle fleet to achieve 57 mpgge (on-road) in 2050.

This scenario envisions significant slowing of growth in transport intensity (per-capita VMT) in each subsector to about half of the *Reference* scenario growth, which translates into a 25% reduction from the *Reference* scenario in per-capita VMT across all modes. In most cases, 2050 transport intensities are still somewhat higher than current (2008) levels, but not significantly so. In the LDV subsector in particular, halving of per-capita VMT growth translates into a 20% reduction in total VMT compared to the *Reference* scenario in 2050. This level of reduction in LDV VMT would require a suite of strong transportation policies: transit, land use, and auto pricing (e.g., road, cordon, and parking pricing; fuel taxes; and pay-as-you-go insurance). Studies from Rodier (2009), Cowart (2008a) and others have estimated that such approaches have the potential to reduce total VMT by 24-29% from business-as-usual forecasts by 2050. Note that to account for a shift from personal to public transport in our model, vehicle load factors of buses and rail are assumed to increase accordingly while LDV load factors remained unchanged.

Table 4 summarizes the *Efficient Biofuels 50in50* scenario, showing, by subsector, the breakdown of fuel usage and the normalized values for transport, energy and carbon

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US ethanol consumption was just 6 billion gge in 2008 [(EPA, 2008c. Renewable Fuel Standard Program. Environmental Protection Agency.].

intensity. By 2050, improvements in vehicle efficiencies have reduced the transportation sector-wide average energy intensity by 63% compared to 1990 levels. This is largely the result of aggressive improvements in efficiency, including vehicle hybridization where possible, being applied in the LDV, HDV, and aviation subsectors (Cheah et al., 2007; IEA, 2008; Yang et al., 2008). As a result of the use of low-carbon biofuels, average carbon intensity of fuels across the entire transportation sector is reduced by 47% compared to 1990 levels. Transport intensity (per-capita VMT) increases by just 52% across all modes in the *Domestic* case and 78% in the *Overall* case, compared to 102% (*Domestic*) and 148% (*Overall*) in the *Reference* scenario.

**Table 4 Description of the Deep Reduction Mixed-Strategy Scenarios, *Domestic* Case.**

| | | Share of Miles by Fuel Type | | | | T | E | C |
|---|---|---|---|---|---|---|---|---|
| | | Conventional Petroleum | Biofuels | Hydrogen | Electricity | Normalized Transport Intensity (1990=100%)* | Normalized Energy Intensity (1990=100%) | Normalized Carbon Intensity (1990=100%) |
| Efficient Biofuels 50in50 | LDV | 0% | 100% | 0% | 0% | 137% | 33% | 13% |
| | HDV | 80% | 20% | 0% | 0% | 149% | 52% | 82% |
| | Aviation | 100% | 0% | 0% | 0% | 234% | 36% | 100% |
| | Rail | 84% | 0% | 0% | 16% | 171% | 59% | 80% |
| | Marine/Ag/Off-road | 100% | 0% | 0% | 0% | 117% | 40% | 101% |
| | All subsectors combined | 35% | 64% | 0% | 1% | 152% | 37% | 53% |
| Electric-drive 50in50 | LDV | 10% | 0% | 60% | 30% | 137% | 24% | 40% |
| | HDV | 72% | 0% | 22% | 5% | 149% | 60% | 100% |
| | Aviation | 20% | 75% | 5% | 0% | 234% | 37% | 32% |
| | Rail | 0% | 0% | 0% | 100% | 171% | 38% | 43% |
| | Marine/Ag/Off-road | 62% | 0% | 38% | 0% | 117% | 40% | 78% |
| | All subsectors combined | 17% | 17% | 42% | 24% | 152% | 33% | 59% |
| Multi-Strategy 80in50 | LDV | 0% | 10% | 60% | 30% | 137% | 22% | 30% |
| | HDV | 0% | 63% | 28% | 9% | 149% | 58% | 19% |
| | Aviation | 0% | 100% | 0% | 0% | 234% | 37% | 14% |
| | Rail | 0% | 0% | 0% | 100% | 171% | 38% | 43% |
| | Marine/Ag/Off-road | 2% | 79% | 20% | 0% | 117% | 40% | 28% |
| | All subsectors combined | 0% | 36% | 40% | 24% | 152% | 32% | 24% |

* For example a value of 137% corresponds to a +37% change from 1990, and a value of 34% corresponds to a -66% change.

*Electric-drive 50in50 scenario*

The *Electric-drive 50in50* scenario assumes the widespread use of high-efficiency electric-drive vehicle technologies running on low-carbon electricity. The LDV fleet makes a major shift towards electrification and by 2050 is composed of 60% hydrogen fuel cell vehicles (FCV), 20% battery-electric vehicles (BEV), and 20% gasoline plug-in hybrid-electric vehicles (PHEV). (In this study, PHEVs are classified as electric-drive vehicles, but HEVs are not.) As a result of this efficient technology mix, the fleet average on-road fuel economy of LDVs is 80 mpgge. This scenario is informed by the optimistic levels of FCV penetration (and accompanying hydrogen production, delivery and refueling infrastructure) modeled by Greene et al. (2007) and NRC (2008) and assumes that BEVs and PHEVs can also make significant inroads by 2050. A similar level of electrification occurs for buses, though heavy trucks are run primarily on diesel and biofuels. Railroads, both passenger and freight, become completely electrified, and a small amount of hydrogen is used to power large oceangoing and domestic freight vessels and for a limited number of aviation (ground operations), agricultural, and off-road applications.

A nontrivial quantity (21 billion gge) of biofuels is consumed in this scenario as well. This level is just below the requirements set forth by the 2007 Energy Independence and Security Act (EISA) RFS, but the biofuels are directed to aviation as a bio-based jet fuel, where they account for three-quarters of all aviation fuels consumed.

Table 4 provides additional details about the *Electric-drive 50in50* scenario. The widespread use of electric-drive by 2050 has led to dramatic improvements in vehicle efficiencies, reducing the sector-wide energy intensity by 67% compared to 1990 levels. The use of low-carbon electricity (described earlier) and hydrogen (primarily from fossil sources with CCS, biomass, and electrolysis from renewables), which account for 66% of total fuel usage, lowers total sector fuel carbon intensity by 41% compared to 1990 levels. Total biomass feedstock consumption (for both biofuels and hydrogen production) is about 0.5 billion bone dry tons (BDT), well within estimated US resource limits. As in the other deep GHG reduction scenarios, the increase in *Domestic* transport intensity is just 52% across the entire sector, a 25% reduction in per-capita VMT from the *Reference* scenario.

*Multi-Strategy 80in50 scenario*

The *Multi-Strategy 80in50* scenario combines the approaches of the two *50in50* scenarios (biofuels and electric-drive) into a single scenario that achieves an 80% reduction in greenhouse gas emissions across the entire transportation sector. For each subsector, assumptions about the efficiency of specific vehicle technologies and behavioral options for reducing transport intensity are the same as in the two *50in50* scenarios. In these two previous scenarios, limitations on the available supply of biofuels and applicability of electric-drive to certain transport subsectors restricted the feasible potential of these strategies to contribute to even deeper GHG reductions.  Greater reductions are achieved the *Multi-Strategy 80in50* scenario by targeting a more optimal distribution of vehicle technologies and fuels. For example, light-duty vehicles and buses, which appear to be the most flexible in terms of the vehicle/fuel options available to them, are predominantly electrified (FCVs, BEVs, and PHEVs), as in *Electric-drive 50in50*. Biofuels supply the small amount of liquid fuel that LDVs and buses consume, and biofuel HEVs comprise nearly all (90%) heavy-duty trucks, with the remainder being hydrogen FCVs used for short-haul and delivery operations. As above, rail is completely electrified, and a small amount (20%) of hydrogen is used in the agricultural and off-road subsectors, generally replacing natural gas and LPG in current use.

The electrification of transport in the subsectors where it is technically feasible frees up biofuels to be used in other subsectors where liquid fuels are most valuable, primarily aviation and marine. Biofuels supply all of commercial, freight, and general aviation; 50% of the fuel demand for large oceangoing vessels; and 25% for domestic freight vessels and personal recreational boats. The balance of marine fuels is petroleum-based, due to challenges in bringing low-carbon biofuels into the international marine fuel supply.

As Table 4 shows, the transportation sector-wide average energy intensity (MJ/mile) is 68% below 1990 levels in this scenario, and total carbon intensity ($gCO_2e$/MJ) is reduced by 76%, meaning average GHG emissions per transport distance ($gCO_2e$/mile) are reduced 92% relative to 1990, a very aggressive yet technically feasible level. Total biomass consumption (for both biofuels and hydrogen production) is about 1.4 billion BDT; this pushes the limits of what the US could potentially produce with domestic resources and assumes no biomass is used for electric generation, which may or may not be a reasonable assumption in the longer-term given the relative economics of competing end-use demands for biomass. As with the two *50in50* scenarios, the increase in transport intensity across the entire transportation sector is only 52%, assuming aggressive transportation demand management strategies are implemented and prove to be effective.

### *I.3.4 Scenario Results and Comparison*

Table 5 summarizes the key results of the three deep emissions reduction scenarios, and Figure 1 shows how GHG emissions are reduced compared to the *Reference* scenario for different activity, fuel, and technology options. For each general strategy, reductions are further broken down into improvements in vehicle efficiency and carbon intensity.

**Table 5 Summary of Results in the Three Deep Emissions Reduction Scenarios**

| ***Scenario Name*** | ***Scenario Summary*** |
|---|---|
| *Efficient Biofuels 50in50* | Emission reductions come from three main areas: slowing travel demand growth (810 $MMTCO_2e$), conventional vehicles (523 $MMTCO_2e$), and biofuels (1,185 $MMTCO_2e$). In the biofuels category, 690 $MMTCO_2e$ of reductions come from substituting biofuels for conventional petroleum fuels, and 495 $MMTCO_2e$ of emission reductions are due to increasing the efficiencies of vehicles beyond those in the *Reference* scenario. Demand for fossil-based liquid fuels is 77 billion gge per year (4.2 mbpd). |
| *Electric-drive 50in50* | Emission reductions come from a more diverse set of approaches. Travel demand reductions, by assumption, provide the same benefit (810 $MMTCO_2e$), but the reduction from conventional vehicles is lower (247 $MMTCO_2e$), as there is a shift towards electric-drive vehicles where technically and economically feasible (primarily LDVs, buses, and rail). Biofuels make a relatively minor impact (270 $MMTCO_2e$) entirely in the aviation subsector. Total biofuels demand is consistent with the EISA2007 RFS. The major technology-related reductions come from using advanced vehicles running on electricity and hydrogen—461 and 754 $MMTCO_2e$, respectively. Demand for fossil-based liquid fuels is 65 billion gge per year (3.5 mbpd). |
| *Multi-Strategy 80in50* | This scenario combines strategies from the two previous scenarios to make even deeper reductions in GHG emissions. Significant cuts in travel demand are still required. The large emissions reductions resulting from each of the key technologies – hydrogen (778 $MMTCO_2e$), electricity (470 $MMTCO_2e$) and biofuels (1052 $MMTCO_2e$) – are essentially the same as in the two *50in50* scenarios which focus on them. Total *Domestic* biofuels demand is 82 billion gge, and some biomass is used for low-carbon $H_2$ production. Demand for fossil-based liquid fuels is nearly zero. |

*Multi-Strategy 80in50* is more successful in making deeper emission reductions because it combines the strategies from the two *50in50* scenarios, which are somewhat complementary, and helps to address their key limitations. Biofuels are convenient replacement liquid fuels that, in theory, can be relatively easily substituted for conventional petroleum fuels in any subsector. In *Efficient Biofuels 50in50*, constraints on biomass resources impose limits to how much biofuel substitution can take place. Electric-drive vehicles such as FCVs, PHEVs and BEVs offer the potential for greatly improved vehicle efficiency and the use of low-carbon energy carriers from a variety of primary resources. In *Electric-drive 50in50*, GHG reductions are limited by the challenges associated with applying electric-drive vehicles to certain subsectors (such as aviation and heavy duty trucks) because of specific technical considerations, most notably energy storage density, as well as temporal limits associated with the market penetration and social acceptance of these vehicles and building their requisite refueling infrastructure.

In each of the three scenarios, slowing the growth in travel demand with a suite of known transit, land use, and pricing policies leads to important GHG reductions across all subsectors. Per-capita VMT still grows by 52%, and total VMT by 157%, but this is considerably slower growth than in the *Reference* scenario (102% and 241%, respectively).

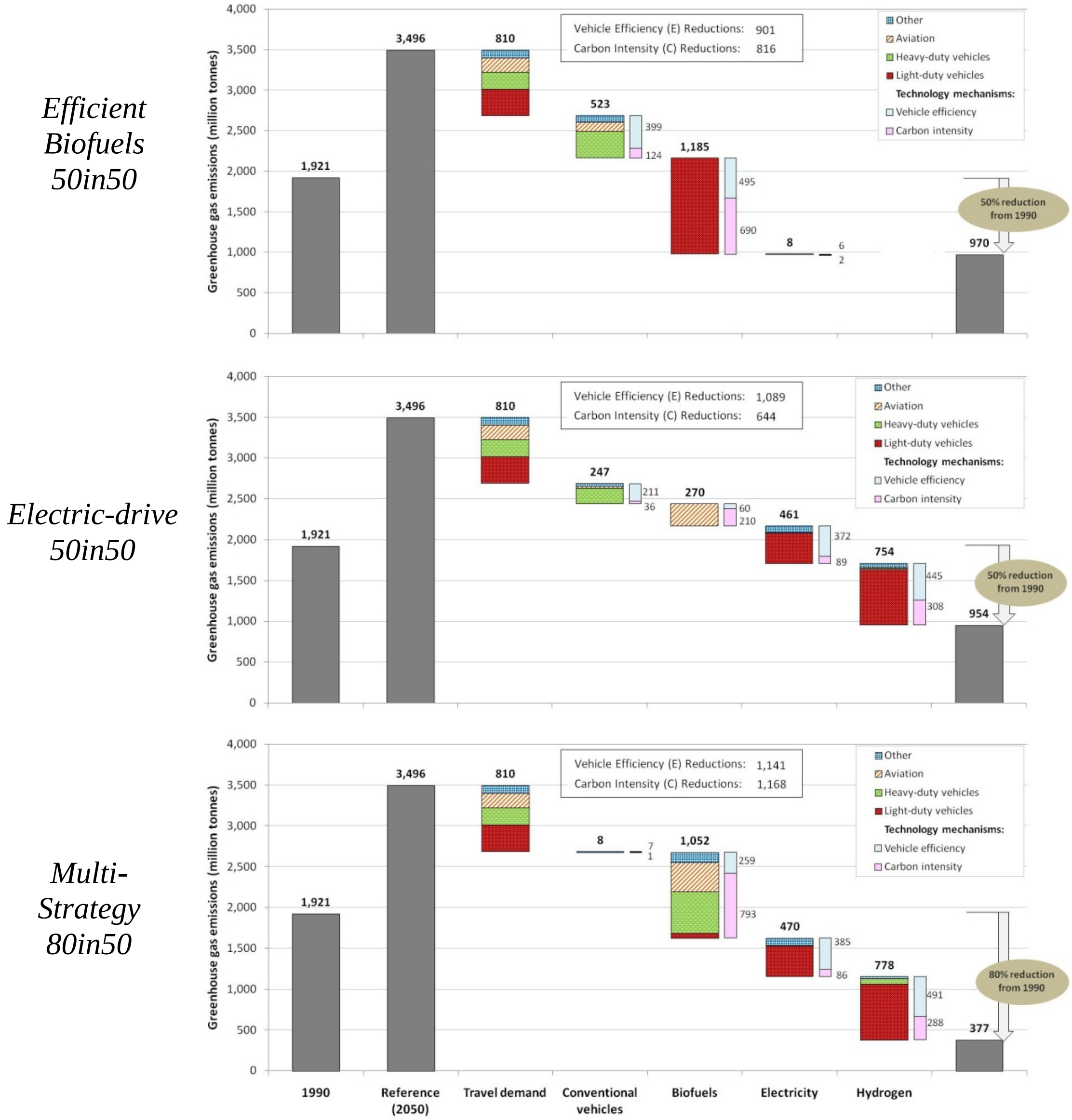


**Figure 1** ***Domestic*** **GHG Reductions by Control Strategy for Three Deep Emission Reduction Scenarios**

Each of the three scenarios relies heavily on fuels with very low-carbon intensities to achieve the deep GHG reduction targets. Hence, they are rather sensitive to assumptions about the fuels production processes. There is a vast range of carbon intensities from different methods for biofuels, hydrogen, or electricity production, and those that result in higher carbon intensity fuels would eliminate much of the emission reductions gained in these scenarios. With biofuels in particular, the scenarios are quite dependent on a large supply of domestically grown or collected biomass, which is directed primarily to low-carbon transport fuels production. Perlack et al. (2005) estimate that more than 1.3 billion bone dry tons (1.18 billion metric tonnes) of biomass per annum could be “sustainably” supplied (without impacting food, feed, and export demands, or displacing corn croplands) in the US in the long-term, if competing demands for biomass are ignored (e.g., electric generation). About two-thirds of this quantity is comprised of residues that would be relatively easy to collect or are already collected for other purposes; the other one-third is comprised of energy crops.[10] If the amount of available biomass resources were constrained to a significantly lower quantity, either because of competing end-use demands or other environmental and economic concerns, then it would be nearly impossible to meet the deep emission reduction goals across the entire transport sector. Similarly, if biomass production cannot achieve such low carbon intensity, because of technology challenges or associated direct and indirect land use change (LUC), then the deep reduction goals will likewise become much more difficult to attain.

The average lifecycle GHG emissions assumed for the biofuels in our scenarios come almost entirely from biomass feedstock production, collection, and transport, and biofuels distribution (Wang, 2007). Future cellulosic biofuels plants, employing either biochemical or thermo-chemical production methods, will likely be energy self-sufficient

[10] Forestlands in the contiguous US could produce 368 million dry tons annually: fuelwood harvested from forests (52 million); residues from wood processing mills and pulp and paper mills (145 million); urban wood residues including construction and demolition debris (47 million); residues from logging and site clearing operations (64 million); and fuel treatment operations to reduce fire hazards (60 million). Agricultural lands could produce nearly 1 billion tons annually: annual crop residues (428 million); perennial crops (377 million); grains used for biofuels (87 million); and animal manures, process residues, and other miscellaneous feedstocks (106 million).

and, therefore, contribute no additional fossil-derived GHG emissions. Furthermore, as other transport modes become more efficient and decarbonized, this will also help to drive down the lifecycle emissions associated with biomass and biofuels production and distribution. We have considered this in our modeling, and it is one reason why the value we assume for average US biofuels (12.3 $gCO_2e/MJ$, excluding indirect LUC impacts) is fairly optimistic.

To be sure, lifecycle carbon intensities of future advanced biofuels are still uncertain (Farrell et al., 2006; Pimentel and Patzek, 2008). One key reason for this uncertainty is due to potential direct and indirect land use changes associated with biofuels production, the impacts of which are not yet fully known (Sperling and Yeh, 2009). Searchinger et al. (2008) have estimated, for instance, that these land use impacts could be as much as an additional 111 $gCO_2e/MJ$ for a specific class of cellulosic biofuels derived from dedicated energy crops grown in the US. Carbon intensities of this large a magnitude would far exceed the lifecycle carbon intensity of gasoline (92 $gCO_2e/MJ$) (Wang, 2007), thus contributing no GHG reduction benefits whatsoever. However, in this study, since only one-third of the available biomass resources we have assumed are energy crops, the indirect LUC impacts would probably be, on average, far lower than these extreme estimates. Two-thirds of the resources we assume are from waste biomass and would, therefore, have no indirect LUC effects at all. Nonetheless, even a small increase in average biofuel lifecycle carbon intensity due to LUC (e.g., +15 $gCO_2e/MJ$) would double the carbon intensity assumed in this study, eliminating much of the GHG reduction potential in the scenarios. In sum, if supplies of low-GHG biofuels are significantly constrained for the reasons mentioned here, then a multi-strategy future with considerable penetration of electric-drive vehicles and decarbonized energy carriers (i.e., $H_2$ and electricity) may be the only real option for making emission reductions across all of transport. In this case, deep transport-wide reductions on the order of 80% may be unachievable, though less stringent targets may still be attainable.

Figure 2 compares fuel consumption and primary resource requirements in the three deep emission reduction scenarios. By aggressively improving vehicle efficiencies across all subsectors, large annual fuel savings can be achieved: 160-185 billion gge in 2050 relative to the *Reference* scenario, or the energy equivalent of 8.7-10 million barrels of oil per day (mbpd). Oil savings are greater in the *Electric-drive 50in50* and *Multi-Strategy 80in50* scenarios, owing to the penetration of higher efficiency electric-drive vehicles. The demand for fossil-based liquid fuels in the three scenarios is low enough to be supplied completely by projected domestic US oil production in 2050, either from conventional or unconventional sources.

The results for primary resource requirements are similar to fuel consumption. Resource requirements in *Electric-drive 50in50* are the lowest of all due to higher end-use vehicle efficiencies. In addition, the diversity of primary resource types is much greater in *Electric-drive 50in50* and *Multi-Strategy 80in50* because the use of decarbonized energy carriers such as electricity and hydrogen provides significant resource flexibility and diversification. The exact resource mixes that are chosen for producing these energy carriers will ultimately be determined by policy, economics, and resource constraints, factors that will affect, and also be constrained by, the resulting carbon intensity of the energy carrier. Note that in contrast to the other two scenarios, *Efficient Biofuels 50in50* is heavily reliant on just two primary energy resources, petroleum and biomass.

While a multi-strategy portfolio approach may be preferred, there are inherent challenges to developing multiple, parallel supply infrastructures for different fuels, as economies of scale and natural monopolies tend to exist. A vast refining and distribution infrastructure for petroleum already exists, and some of this can likely be used for future biofuels distribution. The electricity transmission and distribution system is also vast, though it would need to be expanded and upgraded for widespread use of electricity as a vehicle fuel. Infrastructure for the production, distribution and refueling of hydrogen fuel would likely require the most significant investment and large-scale change.

The EIA's business-as-usual projections for future domestic US energy production in 2030 are sufficient to meet the primary resource demands of the *50in50* and *80in50* scenarios (EIA, 2008a).[11] For biomass and renewable electricity generation, the scenario resource demands are well below the *untapped* supply potential using domestic resources (NREL, 2004; Perlack et al., 2005). Note that the total transportation-related electricity consumption estimates shown for each scenario in Figure 2 include electricity used for vehicle recharging and for hydrogen production and distribution. $CO_2$ capture from hydrogen and electricity production in the scenarios would necessitate storage requirements of at most 430 $MMTCO_2$ per year, well below the roughly 3,600,000 –

[11] EIA's projections for domestic energy production in 2030 include: crude oil (12,699 PJ), natural gas (21,099 PJ), coal (30,202 PJ), biomass (8,570 PJ), total electric generation (17,599 PJ), nuclear power (10,093 PJ), and renewable power (1,991 PJ).

12,900,000 $MMTCO_2$ of storage capacity that is potentially available in US oil and gas reservoirs, unmineable coal seams, and deep saline formations (NETL, 2008).

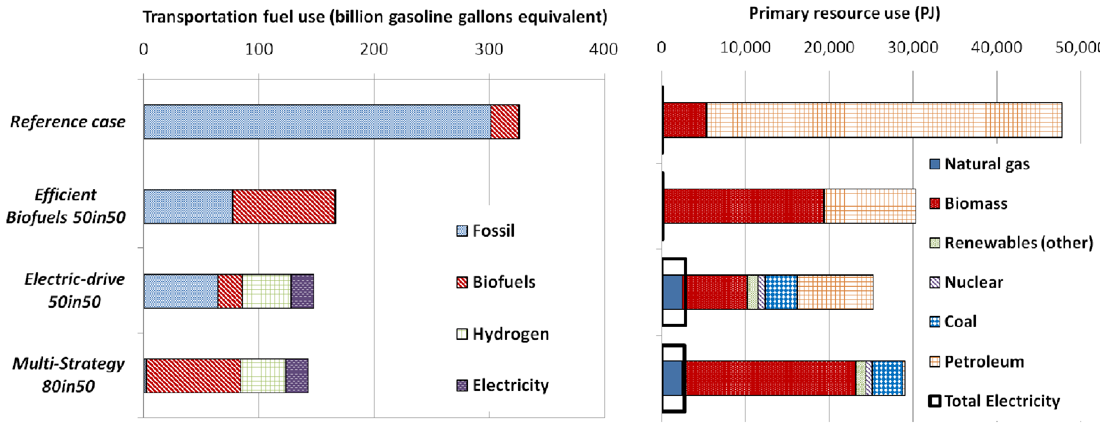


**Figure 2 Transportation Fuel Use and Primary Resource Consumption in 2050 by Scenario (*Domestic* Emissions)**

* Note: "Total Electricity" bar in the Primary resource use figure (right) refers to the total amount of electricity used for transportation purposes in the given scenario. Because electricity is not a primary resource, the bar is superimposed on top of the primary resource bars.

### *I.3.5 Overall Emissions*

The scenarios described here have been designed specifically to meet a goal of 50-80% reduction in *Domestic* emissions. Reducing *Overall* emissions by this amount requires even greater levels of implementation of advanced vehicle technologies, fuels substitution, and/or travel demand reduction. For example, in the *Efficient Biofuels 50in50* scenario, *Domestic* emissions are reduced by 50%, but *Overall* emissions are only reduced by 39%. In *Electric-drive 50in50* and *Multi-Strategy 80in50*, the *Domestic*/*Overall* breakdowns are 50/48% and 80/78%, respectively. If in the *Multi-Strategy 80in50* scenario, the *Overall* case were limited to the same quantity of biofuels and biomass as in the *Domestic* case (82 billion gge, 1.4 billion BDT), then *Overall* emissions would only be reduced by 68%. Achieving an 80% reduction in *Overall* emissions in this scenario by increasing biofuels utilization would require an additional 28 billion gge (+34%) for a total of 110 billion gge of biofuels (or 1.8 billion BDT of biomass, including $H_2$ production). In light of the surging growth of international passenger and goods movement and constraints on biomass resources, it appears it will be a more significant challenge to reduce *Overall* US transport sector emissions by as much as 80%. Considering the substantial efficiency improvements already assumed for air and marine transport, either a greater quantity of biofuels (perhaps from non-US sources) will be required, especially for aviation, or travel intensity in the international aviation and marine subsectors must be kept to levels not much higher than today's.

### I.4 Policy Implications of Scenario Analysis

The US currently has no laws specifically designed to cut GHG emissions, but momentum is growing at both the national and state levels (Litz, 2008; Lutsey and Sperling, 2008; Pew, 2009). In fact, several climate change bills have been proposed in the US Congress over the past several years to set up a domestic cap-and-trade program with a declining cap on annual GHG emissions that would ultimately lead to economy-wide reductions in the range of 50-80% by 2050 (WRI, 2008).[12]

As discussed previously, a combination of transportation sector-specific policies and broad, economy-wide policies will be needed to help tackle emissions from the transportation sector. And within the broad category of transportation policies, there are

[12] An 80% reduction in annual U.S. GHG emissions (from all sources) below 1990 levels is equivalent to an 83% reduction below 2005. Annual GHGs in 1990 were 14% lower than in 2005 [EPA, 2008b. Inventory of U.S. Greenhouse Gas Emissions and Sinks: 1990-2006. Environmental Protection Agency, Washington, DC.].

a many types of policies that can be used to address the three main “levers” – reducing travel demand, improving vehicle efficiency and reducing fuel carbon intensity. Some examples of these policies are fuel economy (MJ/mi), fuel carbon intensity ($gCO_2e$/MJ), and GHG emissions ($gCO_2e$/mi) standards; feebates and/or subsidies for vehicle purchase based upon fuel economy or GHG intensity; fuel and technology mandates; and government investment in technology R&D, fuel infrastructure. Related to addressing these T, E and C factors, there is also the need to target emissions in each of the transportation subsectors. Based upon this framework, gaps in current US climate, energy and transportation policy can be identified where policy fails to address specific mitigation levers in a given transport subsector. By addressing and filling these gaps, the goal of making deep reductions in US transport GHG emissions will become easier to meet.

First, a large portion of transport emissions, namely the non-LDV subsectors, are not covered by any federal or state policies, and this gap in policy is accompanied by a gap in the policy literature related to the best policy tools needed to motivate these reductions within the specific context (i.e., industry and market structure) of a transportation subsector, whether through broad market mechanisms or more targeted policies. Second, while the literature is relatively robust on the technological options available for achieving emissions reductions by pulling the energy intensity (E) and carbon intensity (C) levers (many of which have been mentioned in this chapter), far less research has addressed transport intensity (T) as a strategy for achieving GHG reductions, especially with respect to the non-LDV subsectors.

### *I.4.1 Vehicle Efficiency*

The new CAFE standards will help reduce LDV GHG emissions in an important way, but the *Reference* scenario shows that in the absence of future increases in CAFE, LDV fuel use and GHGs will both continue to increase dramatically. Two *Silver Bullet* efficiency scenarios were developed that show the benefits of further energy intensity reductions beyond the most recent CAFE standards. Yet, improved efficiency alone is not enough to achieve significant GHG emission reductions from 1990 – the scenarios achieve an average LDV on-road fleet fuel economy of 51 and 61 mpgge, respectively, with other subsectors increasing their average efficiency a comparable amount by 2050. As a result, the fuel economies that LDVs need to achieve in the *50in50* and *80in50* scenarios are even higher. Figure 3 compares the scenario fuel economies to current and proposed fuel economy standards in the US, California, and several other countries. The trajectory of fuel economy improvement over the next several decades would clearly be steep; however, one should keep in mind the step changes in efficiency improvements that HEVs, BEVs, PHEVs, and FCVs make possible.

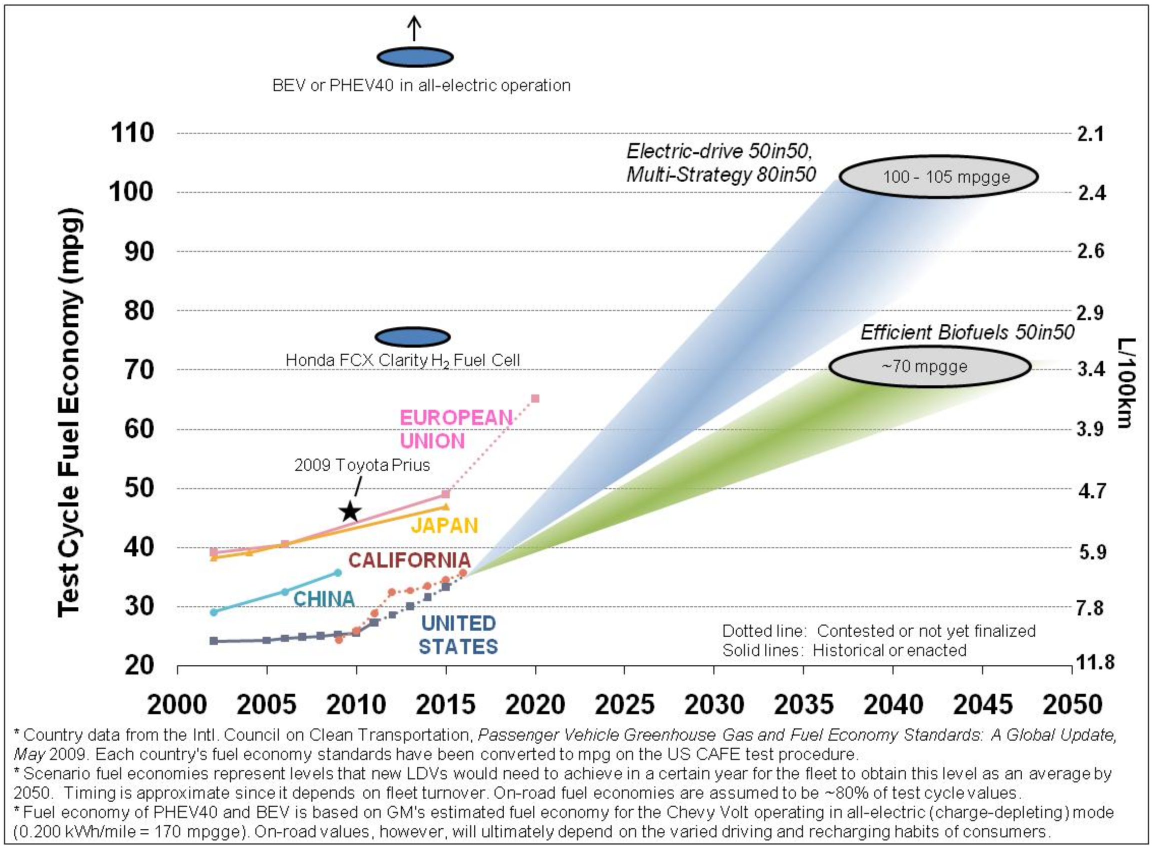


**Figure 3 Fuel Economy Standards for New LDVs by Country/Region Compared to Average Fuel Economies of New LDVs in *50in50* and *80in50* Scenarios**
**(Figure obtained from ICCT (2008) and modified. Reproduced with permission)**

This analysis shows that any serious policy portfolio to reduce transport GHGs must deal with the policy gaps in other subsectors, particularly those growing the most rapidly—heavy-duty trucks, large marine vessels, and aviation. Higher efficiency vehicles in other subsectors, such as those in the *50in50* and *80in50* scenarios, are necessary for deep emission reductions since LDVs cannot, by themselves, reduce total transport GHGs 50-80%. There have never been efficiency standards for the non-LDV transport modes, thereby leading to the historical underinvestment in more efficient technologies.[13] The long lifetimes of these types of vehicles (compared to LDVs) require that policies setting minimum efficiency standards be enacted soon so that fleets can incorporate these technologies by 2050. Importantly, US action in this area can have global consequences for future aircraft and shipping technologies since it accounts for such a large share of combined global demand and because there are only a few major aircraft and ship manufacturers in the world.

### *I.4.2 Fuels Policy*

The *50in50* and *80in50* scenarios all have very significant reductions in average fuel carbon intensity relative to 1990 (41-47% for the *50in50* scenarios and 76% for the *80in50* scenario), highlighting the importance of reducing carbon intensity in meeting the targets. Because there are no options for significantly reducing carbon intensity from petroleum fuels, reducing fuel carbon intensity requires switching to alternative fuels. The US does not have any federal policies expressly designed to reduce fuel carbon intensities, though the biofuels mandates in the existing federal RFS contain some language addressing this issue. A more robust and durable option which is currently under discussion at the federal level may be a low carbon fuel standard (LCFS), because it specifies GHG performance rather than mandating a specific type of fuel. Some have argued that a LCFS is a more direct and effective policy than a RFS (i.e., fuel mandate) for spurring innovation and reducing consumer and industry risk and uncertainty (Sperling and Yeh, 2009). A LCFS and vehicle mandate program could also be extended

[13] The principal-agent problem is one reason for this underinvestment, which is a market failure that distorts incentives for investing in efficiency (IEA, 2007. Mind the Gap -- Quantifying Principal-Agent Problems in Energy Efficiency. International Energy Agency..

to subsectors other than just LDVs in order to address the gap in regulation of other transportation subsectors and spur the development and use of alternatively-fueled planes, ships, heavy trucks, etc. In the absence of such policies, achieving the fuel mixes and carbon intensity values postulated in the *50in50* and *80in50* scenarios would be challenging.

This analysis lends further support to the notion that vehicle efficiency standards, travel demand management strategies, and fuels policy are complementary. Higher vehicle efficiencies and reduced travel demand growth in all subsectors decrease total fuel requirements and improve the effectiveness of resource-constrained fuels, such as biofuels, by allowing them to replace a greater share of total US transportation fuel demand. If biofuels are to make a meaningful contribution to deep emission reductions, then the constrained US biomass resource base must be extended as far as technically possible. Of course, it is still unclear as to how much biomass will ultimately be available for biofuels production, given competing demands for other end-uses (e.g., electricity production), the “food vs. fuel” conflict, water consumption issues, and land use change concerns. In this scenario analysis, we take these important concerns into account and assume that they are adequately addressed when supplying biofuels by limiting production to sources which can be “sustainably” supplied—e.g., agricultural and forest residues, municipal solid wastes, and energy crops requiring minimal irrigation water (Perlack et al., 2005). Ultimately, robust policies will be needed to incentivize the production of sustainable biofuels.  Low carbon fuel standards appear to be the most direct and effective policy strategy for doing this (Sperling and Yeh, 2009).

The options for alternative fuels and advanced drivetrain technologies are more limited in certain subsectors than others, as technical challenges with the use of electricity and hydrogen, such as energy storage density, fast refueling times, and cost, become much more important (IEA, 2008; IPCC, 2007; Yang et al., 2008). As the *Multi-Strategy 80in50* scenario illustrates, using electric-drive technologies with hydrogen and electricity for LDVs, railroads, and buses, enables the use of limited biofuel resources in the other subsectors (i.e., aviation, marine and heavy-duty trucks). Policies may be needed to incentivize this arrangement.

Moreover, for many vehicle applications, ethanol is not an ideal fuel, and the biofuels that are likely to be used in these other subsectors will more closely resemble diesel and jet fuel than gasoline. However, most of the recent activity in biofuels has focused on the biochemical production pathway (i.e., hydrolysis followed by fermentation), even though thermochemical conversion is better suited to the production of bio-derived gasoline, diesel, and jet fuels. Given known constraints on biomass resources and the potential longer-term needs for biofuels, both pathways should be pursued and supported. Thermo-chemical production also offers greater output flexibility and is more amenable to low-carbon electricity generation.

Finally, there is some evidence that the full emissions benefits of low-carbon biofuels would not be realized if they are used in aviation due to the effects of non-$CO_2$ gases and particles released in the upper atmosphere, as discussed previously. For example, in the

*Multi-Strategy 80in50* scenario including an uplift factor of 1.5 or higher on non-$CO_2$ aviation emissions (from Marbaix et al. (2008)) would more than double the effective emissions from that subsector and eliminate much of its reduction potential. Similar considerations exist even for hydrogen aircraft fuel used in a combustion engine, as increased emissions of $H_2O$ and $NO_x$ at cruising altitude (compared to conventional jet fuel) would negate a portion of hydrogen's carbon mitigation potential.

### *I.4.3 Implications of Uncertainty*

Any attempt at forecasting future demands and technologies will, invariably, get many things wrong (Craig et al., 2002). There are many uncertainties in all of the assumptions within this study, about the potential and readiness of specific technology and behavioral options. We attempt to address some specific questions about uncertainty with respect to policy and technology development in areas that many readers may be aware of. However, given the wide range of assumptions, it is difficult to discuss all of the important uncertainties in every area or make a comparison of the relative uncertainties that underlie our assumptions.

Developing durable and robust policy for the 2050 time horizon is challenging because the process must rely on a host of uncertainties. The major uncertainties associated with the *Efficient Biofuels 50in50* scenario center on the future availability of low-carbon biofuels (including key questions of total availability, their true lifecycle carbon intensity, and land-use and water impacts). In *Electric-drive 50in50*, the uncertainty centers around the future potential of FCVs, PHEVs, and EVs to penetrate different subsectors (including questions of cost and the adequacy of energy storage and driving range) and the production of low-carbon hydrogen and electricity on a massive scale (including the technical and economic feasibility of CCS and reliable renewable electricity, as well as of their social acceptance). A durable, robust policy will avoid picking winners while these uncertainties become resolved over time, while recognizing that some strategies are more uncertain than others and will therefore take longer to resolve.

Because predicting the course of technology in the future is impossible and there is a poor history of picking technology "winners" from among a suite of possible contenders, this analysis has attempted to look at several possible scenarios involving different types of advanced vehicle technologies and fuels. Putting a cost on carbon and GHGs and implementing other policies will enable the market to decide which options will ultimately prevail and provide significant levels of mobility while reducing emissions. That said, one can still say a few words about the current status of technologies and their potential in the future. Despite much recent progress in batteries and hydrogen fuel cells (namely costs, storage densities, and/or conversion efficiencies), BEVs and FCVs still remain longer-term and more uncertain options than using HEVs, PHEVs, and biofuels (at least at relatively low volumes) (IEA, 2008). While some consumer BEVs already exist, they still suffer from a combination of technical (battery storage, limited range) and economic (battery cost) challenges, both of which will take time to resolve before the BEV can truly be a mass-market vehicle. For FCVs, the major challenges center on vehicle costs and the rollout of the requisite hydrogen production, distribution, and refueling infrastructure. Low-carbon biofuels, HEVs, and PHEVs do not appear to face the same degree of challenges, though even in the nearer-term, options such as biofuels and PHEVs still require considerable technological development. In both cases, costs must be reduced, and with biofuels it is not entirely clear what their lifecycle carbon footprint will ultimately be when produced on a massive scale, considering direct and indirect LUC impacts, as discussed in Section I.3.4. Progress has also been made in CCS technology and geologic reservoir characterization in recent years; and researchers in a number of countries hope to resolve some of the remaining uncertainties in the next few years by constructing demonstration power plants that will capture and sequester $CO_2$. Nevertheless, the future viability of CCS is still unknown and is not yet at the stage where it can be relied upon (MIT, 2007); though, this is true of advanced vehicle technologies like BEVs and FCVs as well. The potential of renewable electricity is arguably more certain than CCS, but questions surrounding its reliability, intermittency, and cost will likely remain for some time (IEA, 2008). Widespread use of renewable electricity may require substantial investment in energy storage systems or upgrading electrical transmission and distribution systems, as well as “smart grids”, yet another source of uncertainty (Chupka et al., 2008).

In this scenario study, the efficiency of different vehicle technologies, the emissions associated with different fuel production methods, and the efficacy of travel demand reduction strategies are all specified as input assumptions. However, real policies designed to bring about these technologies, fuels, and demand reductions must deal with uncertainty and risk in their actual implementation and impact. Reliance on one strategy, such as biofuels, leaves the ultimate level of GHG reduction susceptible to future uncertainties in, for example, the resource availability of biofuels, indirect LUC, and the evolution of fuel production technologies. The diversification of GHG mitigation strategies (i.e., developing a portfolio of mitigation options) that is seen in the various *50in50* and *80in50* scenarios, which involves travel demand reductions, vehicle efficiency improvements, advanced vehicle technologies, alternative fuels, and reductions in fuel carbon intensity, not only makes it easier to achieve the deep emissions reduction goals, but also helps mitigate the reliance (and therefore sensitivity) of the overall reductions to any one technology or option.

#### *I.4.4 Other Policy Implications*

This analysis is based upon an extensive review of the literature to assess the potential for GHG emissions reductions in each of the transportation subsectors, which then provides the basis for the many input assumptions into the LEVERS model. As with any model, these assumptions are still in need of further refinement as more and better information about these options becomes available, especially in key areas where fewer analyses have been undertaken or where greater uncertainties have yet to be resolved. For instance, there are many sources of information about mitigation options for the LDV subsector; however, the literature is not nearly as extensive for the other subsectors. This makes it challenging to fully understand these sectors' potential for adopting alternative drivetrains, alternative fuels, and especially options for transportation demand management. In addition to technical analysis, more analysis is needed on the policy side to better understand these other subsectors, their current and future structure and the appropriate incentives that are needed to bring about emissions reductions.

Moreover, the findings of this study provide further analytical support, particularly in the US context, to a notion that has been advanced by others: behavioral and structural changes must complement technological change if deep reductions in transportation GHG emissions are to be achieved (Gallagher et al., 2007; IEA, 2008; Mui et al., 2007; Samaras et al., 2009; Sperling and Gordon, 2008). While most policies being discussed address fuel carbon intensity (C) and vehicle energy intensity (E), strong policy is needed to pull the transport intensity (T) lever as well. Without addressing T in the *50in50* and *80in50* scenarios, it would be considerably more difficult, if not impossible, to make such deep reductions in GHGs by 2050. Because the built environment has a decades-long lifetime, land-use plans and infrastructure development that are implemented today will impact GHG emissions in 2050.

There are currently no federal policies specifically designed to reduce GHG emissions by addressing growth in travel demand, and certainly none to limit population (P). However, over the past several decades, many US states and firms have implemented a variety of travel demand management (TDM) policies and strategies in an attempt to slow the growth in LDV VMT and thereby reduce the impacts of transportation externalities such as air pollution, congestion, and noise (Berman and Radow, 1997; DOT, 2004; Saleh and Sammer, 2009). These and other proposed actions include road, cordon, and parking pricing; fuel taxes; pay-as-you-go insurance; high-occupancy vehicle (HOV) lanes; ridesharing; employee incentives for telecommuting and transit; and traveler information systems. For a variety of political and institutional reasons, these actions have generally failed, thus far, to significantly slow the rapid growth in total national VMT. Though, success has been achieved in certain locales, and studies indicate the potential for TDM strategies to reduce future fuel use and GHG emissions could actually be quite substantial (Cowart, 2008a; Deakin et al., 1996; Rodier, 2009; Safirova et al., 2007; UKERC, 2009). Still, addressing transport intensity as a key driver for reducing emissions remains inherently complicated. A potentially unique way forward is the linking of regional land-use planning to GHG reduction targets, as California's landmark anti-sprawl legislation (SB 375) is the first to do. Moreover, continued thought should be given to the implementation of TDM measures in the other transport subsectors where consumer choice can be influenced, namely commercial aviation. In the case of freight transport (trucking, rail, aviation, and marine), TDM measures may not be the most appropriate method for controlling emissions, as shippers are very sensitive to costs (in addition to factors such as timing and reliability) and may respond sufficiently to carbon prices.

## I.5 Conclusions

This study explores several scenarios which achieve 50-80% reductions in US transportation sector carbon emissions below 1990 levels by 2050 through incorporation of significant technological and behavioral changes. A Kaya framework that decomposes GHG emissions into the product of four major drivers—population (P), transport intensity (T), energy intensity (E), and carbon intensity (C) – is integrated in our scenario analysis model, LEVERS, to analyze mitigation options and emissions. In addition, our LEVERS framework includes all major transport subsectors—light duty vehicles, buses, heavy-duty trucks, rail, aviation, marine, agriculture, off-road, and construction. While the values for reduction potential from various options in each of the subsectors come from an extensive review of the literature, these inputs, as with any model inputs, are always in need of further refinement. Fortunately, within our simple modeling framework, the assumptions can be easily improved as more information about, and a better understanding of, these options becomes available.

The unique contributions of this study are three-fold. First, the treatment of the transportation sector is broader and more detailed here than in many other scenario and economic studies that have just concentrated on light-duty vehicles. Second, this study utilizes a relatively simple, easily adaptable modeling approach, which can incorporate insights from other modeling studies and organize them in a way that is easy for policymakers to understand. In fact, the model is being used by other researchers and analysts in the development and analysis of transportation, energy, and climate policy. Thirdly, this analysis develops multiple distinct scenarios to understand the interplay between the adoption of specific mitigation options in different transport subsectors and the level of GHG reduction. We believe there is value in approaching the problem in these ways, as opposed to the more "black box" approach of complex energy-systems models, although the latter offers numerous advantages as well.

The scenarios presented in the chapter illustrate the enormous challenges associated with making deep GHG reductions in the transportation sector. While the scenarios represent only a small subset of all potential futures that could potentially meet the 80% reduction target, they provide value by showing the diversity of approaches that might be pursued. These scenarios, first and foremost, are meant to convey the scale and scope of the changes required to meet this aggressive target and to motivate the aggressive action (i.e., policy and technological development) that will be required in all transport subsectors and on all fronts (vehicles, fuels, and travel demand management). In addition, consumers, firms, and society will need to be provided with the appropriate incentives to value the long-term goal of climate change mitigation so that they purchase low-carbon vehicles and fuels and consume the appropriate amount of transportation services.

The *Silver Bullet* scenarios confirm results from other studies, showing that no one mitigation option can singlehandedly meet the ambitious GHG goals, especially since total travel demand (P x T) in each subsector is expected to increase significantly by 2050. This puts a large burden on vehicle and fuel technologies (E x C) to decarbonize, and by our estimates it is unreasonable to think a single technology approach can shoulder this burden entirely on its own, given the diversity of vehicle types and requirements in the transportation sector.

When multiple technological strategies are combined together in a portfolio approach, however – assuming the wide array of technical, economic, social, and policy challenges can be overcome – the potential for emission reductions could be great, as the *50in50* and *80in50* scenarios highlight. This mixed strategy approach would include (1) restraining the growth in travel demand with strong transport and land use planning policies, and (2) targeting advanced technologies and fuels to the subsectors where they are most feasible. Because multiple options are employed, the portfolio approach reduces the required level of vehicle and fuel technology development and usage for any given mitigation strategy.

A portfolio approach also helps to reduce the sensitivity of GHG emissions to any one technology, resource, or behavioral change and the associated risks if the strategy does not succeed.

Though this analysis focuses mainly on *Domestic* emissions, the results of all of the scenarios show that meeting a 50-80% reduction in *Overall* emissions is more challenging. The main issue stems from the greater importance of the aviation and marine subsectors in international travel and the inherent challenge of decarbonizing these two subsectors.

Constraints on primary resources and the penetration of new technologies into the market could put limits on how deep emissions might be reduced. In particular, biofuel production is limited by the total amount of biomass resources available in the US and globally. The use of electric-drive vehicles will not likely be limited by resource constraints, but challenges will arise from the timing of technology development and cost reductions in light of the slow turnover of vehicle fleets, as well as from the limited applicability of electricity and hydrogen outside of on-road, rail, and perhaps some marine applications. Deep emission reductions are also particularly sensitive to fuel carbon intensities. This depends on the land use impacts (direct and indirect) of expanded biomass production and the potential of CCS to decarbonize fossil-based electricity and hydrogen production, neither of which is fully understood at this time.

The extent to which the transport sector will ultimately need to reduce its emissions is not certain since deep reductions are not yet law and reductions will likely not be equal across all sectors of the economy. But as one of the largest current contributors to total US GHG emissions, transportation must play a major role (IEA, 2008; Yeh et al., 2008). If the US is to have a low-carbon transportation sector by 2050, it will need to expand its policy toolkit in order to adequately address emissions from all subsectors. A diverse, portfolio approach for mitigating GHG emissions necessitates continued research and policy support for improving vehicle and fuel technologies and reducing transport intensity. While the potential carbon impacts of the various technology options are relatively well understood, the impacts of the behavioral options are less so, especially in the non-LDV transport subsectors (UKERC, 2009). Behavioral and structural changes, and policies promoting them, are critically important to alleviate dependence on future technology developments and also to reduce other non-GHG-related problems related to unchecked growth in travel demand, including traffic congestion and fatalities.

Comparison of our results and conclusions to those of other recent scenario studies is made difficult by the fact that no other studies have analyzed the issue of long-term transport sector GHG reductions in quite the same way. Either the studies have taken a much more limited view of the transport sector, choosing to focus only on LDVs (e.g., (Bandivadekar et al., 2008; Grimes-Casey et al., 2009; Mui et al., 2007; NRC, 2008; Yeh et al., 2008)), or the focus has not been on the US specifically (e.g., (IEA, 2008; WBCSD, 2004)). Nevertheless, the central conclusion of this analysis is consistent with these other studies: a multi-strategy, portfolio approach is needed in order to make deep reductions in transport GHG emissions, given physical constraints on resources and technological constraints on the types of fuels and vehicles that can be applied in certain subsectors. Another important conclusion, which is consistent with IEA (2008), is that achieving deep reductions will require the decarbonization of the non-LDV subsectors, as emissions from these subsectors are projected to account for greater than half of all US transport emissions by 2050.

There are a number of limitations to the scenario approach employed in this study, and certain caveats apply to the results presented here. First, the analysis is based on hundreds of input assumptions which have been developed from dozens of published studies. While we have tried to be as judicious as possible in selecting assumptions that are the most reasonable, the reader will undoubtedly disagree with some of our choices and, potentially, our results and conclusions. For this reason and in an attempt to be transparent, we include all of our input assumptions in an appendix that can be found in the online supplementary material to the original *Energy Policy* paper, on which this chapter is based. Another limitation of this study is that it focuses on only one sector of the economy, transport, and does not attempt to model GHG mitigation potential in other sectors. In order to account for the transport sector's spillover effects in other sectors, we use lifecycle GHG emissions rather than end-use emissions in our calculations. Since lifecycle emissions are quite sensitive to modeler assumptions, we have based our LCA estimates on the widely used and relatively transparent GREET model. Moreover, in attempting to represent various 2050 snapshots of the US transport sector, we do not explicitly model economics and dynamics in our analysis; though, it should be noted that all of our input assumptions are informed by studies that do consider these important elements.

### I.6 Acknowledgements

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# RESEARCH STREAM #2

## II. Modeling optimal transition pathways to a low-carbon economy in California: Impacts of advanced vehicles and fuels on the energy system (CA-TIMES)

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**Abstract:**

Climate change could have a large impact on California's economy, natural and managed ecosystems, and human health and mortality; and because of this, the state has taken a leading role in regulating greenhouse gas emissions. Yet, while California has taken major steps defining technology pathways and designing complementary policies and regulations to meet its 2020 target of bringing total emissions back down to the 1990 level, the steps needed to achieve the state's long-term, aspirational goal (80 percent below the 1990 level by 2050) have not been clearly defined, and the technology and policy options are not well understood. In an effort to better inform the policy process, I have worked with colleagues to develop a new simulation tool for modeling California's future energy system and for generating and analyzing scenarios for meeting the state's long-term (2020-2050) GHG emission reduction goals. In this capacity, the work offers the unique capability to perform scenario analyses, evaluate policy, and present

technological portraits for the specific conditions that exist within the state. This dissertation chapter provides a detailed description of the modeling tool, which has been named CA-TIMES and is the first bottom-up, technologically-rich, integrated energy-engineering-environmental-economic systems model of its kind for California. The model has been developed within the TIMES framework (The Integrated MARKAL-EFOM System), and it covers all sectors of the California energy economy, including primary energy resource extraction, imports/exports, electricity production, fuel conversion, and the residential, commercial, industrial, transportation, and agricultural end-use sectors. Using the model, I analyze the structure and operation of the future California energy system under various future energy demand scenarios, technology assumptions and carbon policies and evaluate the impacts of these various scenarios in terms of investments in technologies, technology and infrastructure adoption, fuel use and resource demands, electricity generation mix, and environmental impacts, namely GHG emissions. The scenario analyses and model runs focus on the evolution of the transportation, fuel supply, and electric generation sectors, specifically the use of advanced technologies and alternative fuels in response to various energy and climate policies. In sum, achieving deep reductions in California greenhouse gas emissions is technically feasible in the long term at reasonable cost (total cumulative policy costs of <2.7% of Gross State Product, considering only the transportation, electricity, and fuel conversion sectors). Actually, the *net* cost to society could be even lower, when one considers avoided costs (such as for climate change adaptation) and other co-benefits (such as air pollution and energy security). The current analysis does not capture these other benefits (i.e., negative costs). To be sure, the deep reductions envisaged in this analysis are dependent on the full availability of a low-carbon technology portfolio. If the potential of certain key resources and technologies (e.g., biomass, nuclear power, CCS, or electricity and hydrogen as transportation fuels) is significantly limited, then it could become extremely difficult, as well as more costly, to reach an 80% reduction target by 2050.

## II.1 California Energy Use and GHG Emissions in the Base-Year 2005

In developing future energy scenarios for California, it is first necessary to take a historical perspective of energy use and greenhouse gas emissions in the state. The overview provided in this section paints a picture of California's energy landscape as it existed in 2005, which is used as the base-year throughout this study, since a considerable amount of data exists for 2005 and also because it is in the not-too-distant past.

### *II.1.1 End-Use Energy Demand in the Transportation, Industrial, Commercial, Residential, and Agricultural Sectors*

California's energy system is largely reliant on fossil fuels, though a significant amount of energy is also sourced from nuclear, hydro, biomass, and various other types of renewable and non-renewable fuels. Much of this energy is either produced and/or converted to a finished fuel product within the state, in order to meet the ever-increasing demands of the five end-use sectors: Transportation, Industrial, Commercial, Residential, and Agricultural. Figure 4 depicts final energy consumption for each of these sectors in 2005. All values shown here and throughout this chapter reflect the use of higher heating values (HHV) when converting from native units (e.g., kg, scf, lbs) to energy units (e.g., PJ, MJ). In fact, all energy flows in CA-TIMES are estimated on a HHV basis.

It is important to note that according to the definition of *final* (i.e., *end-use*) *energy consumption* that is applied here, the numbers shown in the following figures do not include conversion of primary energy resources (e.g., crude oil, natural gas, coal, etc.) to final energy carriers (e.g., electricity, gasoline, diesel, etc.) at oil refineries, electric power plants, and other types of fuel conversion facilities. If primary energy consumption were allocated to each of the end-use sectors in fair proportions, the energy shares shown here would look quite a bit different indeed. (For example, the transport share would be significantly smaller.) In short, the greater the use of fuel combustion for the purposes of useful work (e.g., moving a vehicle) – as opposed to heat – the greater will be the end-use energy demand. Since work-related fuel combustion processes (e.g., internal combustion engines) are inherently inefficient, total energy consumption in, say, the transport sector is over-emphasized compared to the other end-use sectors where electrically-powered consumer devices and fossil fuel heaters/cookers play dominant roles. The major efficiency losses associated with, for example, electricity generation occur at the power plant stage – i.e., during the conversion from primary to final energy. (While there are certainly efficiency losses at refineries associated with converting crude oil to gasoline, diesel, jet fuel, and all other refined products, these losses are small in comparison to power plants and internal combustion engines.) Because these power plant efficiency losses are ignored, the results shown here for final energy consumption by end-use sector provide a different picture than one might expect if looking only at primary energy consumption.

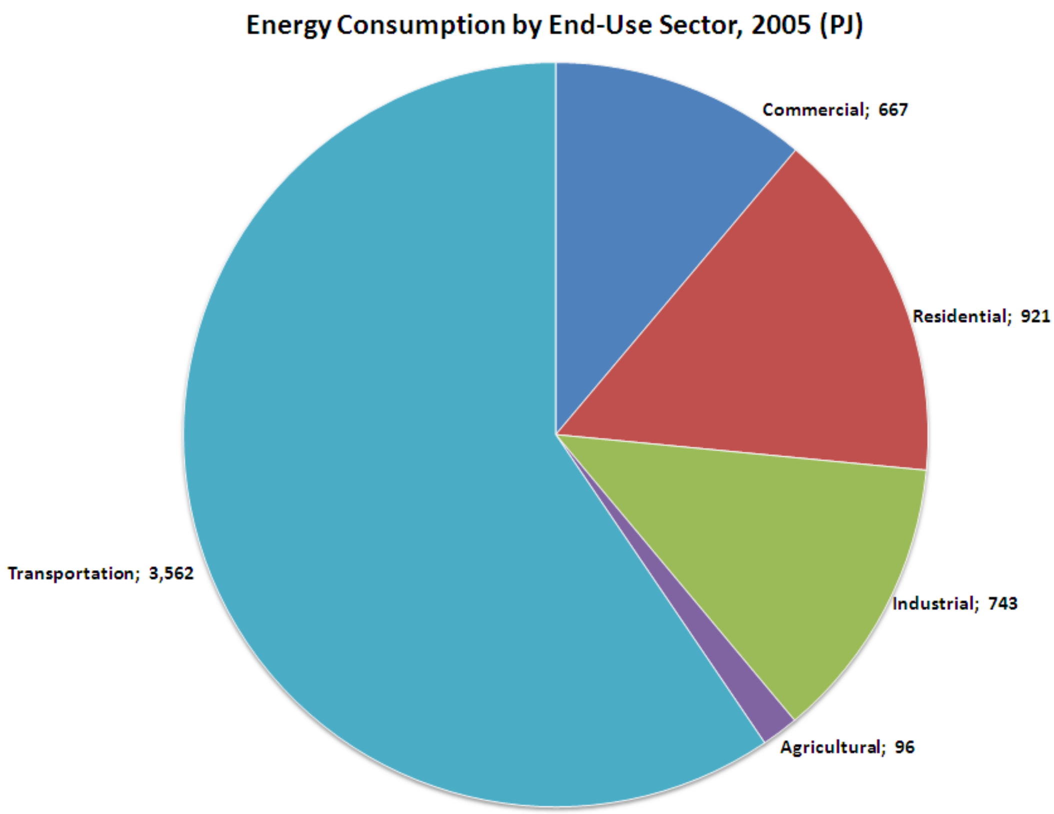



**Figure 4  Final Energy Consumption by End-Use Sector, 2005**

California's commercial sector accounts for about 11% of total energy demand in the state.  The two most consumed fuels are, by far, electricity and natural gas (Figure 5). Certain other fuels, such as distillate, coal, kerosene, LPG, wood, gasoline, and geothermal energy, are used in far smaller quantities.

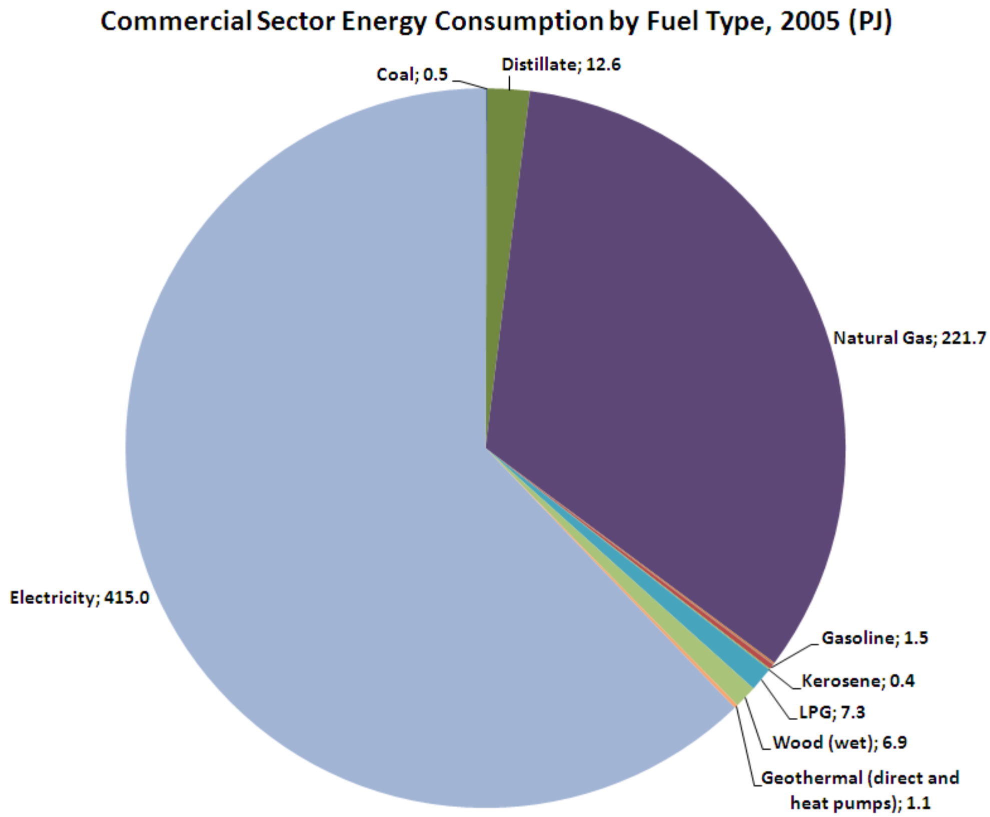



**Figure 5  Commercial Sector Final Energy Consumption by Fuel Type, 2005**

The residential sector is very similar to the commercial sector in its share of total end-use energy demand (~15%) and in that electricity and natural gas are the two dominant fuels (Figure 6). However, in this case the situation is actually reversed – natural gas is the principal fuel, and electricity assumes the minority role. Moreover, solar energy, in the form of rooftop solar photovoltaics and passive solar water heating, comprise a non-trivial share of residential energy supply.

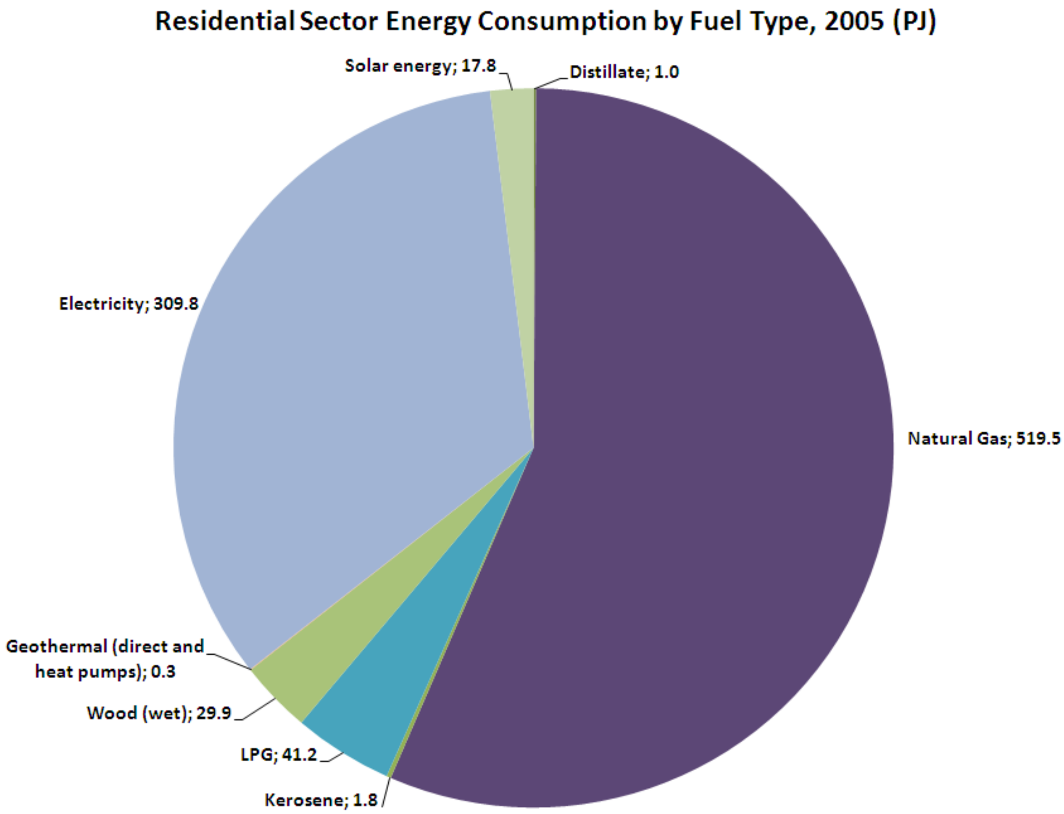



**Figure 6  Residential Sector Final Energy Consumption by Fuel Type, 2005**

The industrial sector accounts for about 12% of California's total end-use energy demand. When compared to some other states and countries, this is actually a relatively small fraction, though it should hardly be surprising given that heavy industry is not the basis for California's economy. That being said, the industries that do exist in California are relatively diverse; hence, the fuels consumed in the industrial sector are also quite diverse (Figure 7). Natural gas and electricity continue to play the two dominant roles, but a number of other fuels are also used in fairly significant quantities, for instance, coal, gasoline, distillate, and biomass, as well as niche fuels such as asphalt and road oil and lubricants, which according to the CARB GHG Inventory are actually combusted for energy purposes in California, thereby generating GHG emissions.

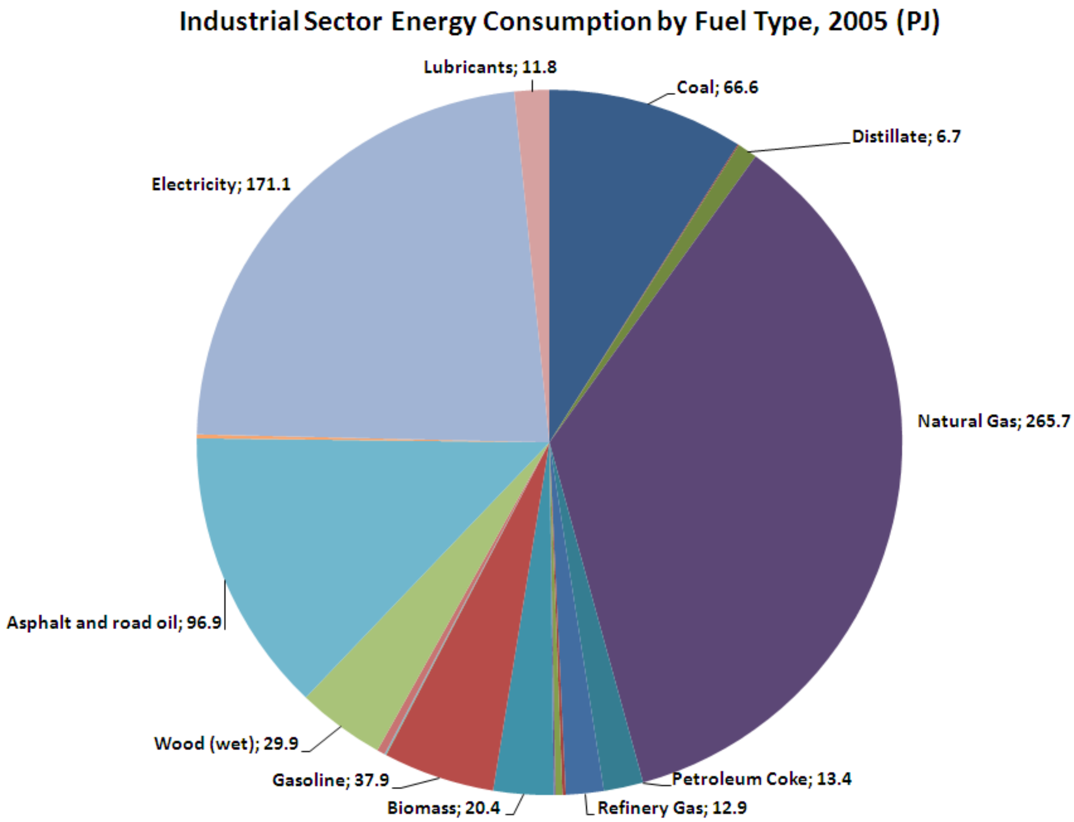



**Figure 7  Industrial Sector Final Energy Consumption by Fuel Type, 2005**

The smallest of California's end-use energy sectors is agriculture.  It accounts for only 1.6% of the state's total energy demand, despite the fact that agriculture plays such an important role in California's economy and society.  Note that although it may not be so clear from Figure 8, fuel consumption for agricultural vehicles is not included here, but rather in the transportation sector.  Yet, even if energy demands for agricultural vehicles were included, total energy demand for the agricultural sector would still only amount to 2.3% of all end-use energy consumption in California.

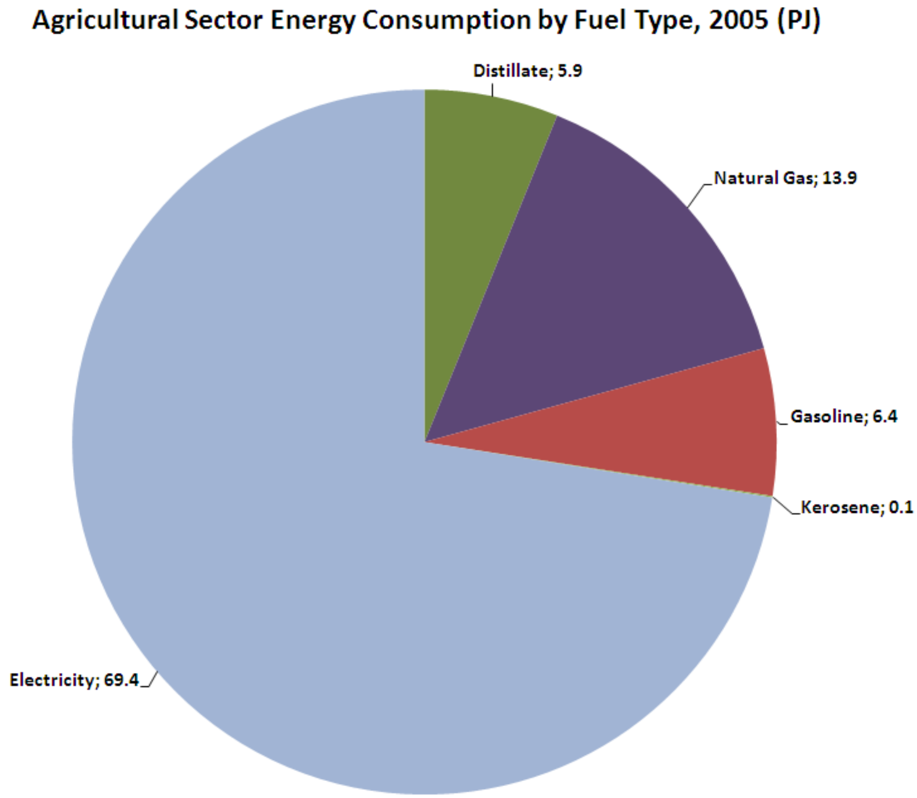



**Figure 8  Agricultural Sector Final Energy Consumption by Fuel Type, 2005 (does not include energy consumption for agricultural vehicles)**

The largest end-use energy sector in California is transportation, which by itself consumes more energy than all of the other end-use sectors combined, accounting for roughly 60% of the state's entire end-use energy demand (Figure 4).  The most important transport sector fuels are petroleum-based: gasoline, diesel (i.e., distillate), jet fuel, and residual fuel oil.  Natural gas, electricity, and ethanol are used as well, albeit at much lower levels.

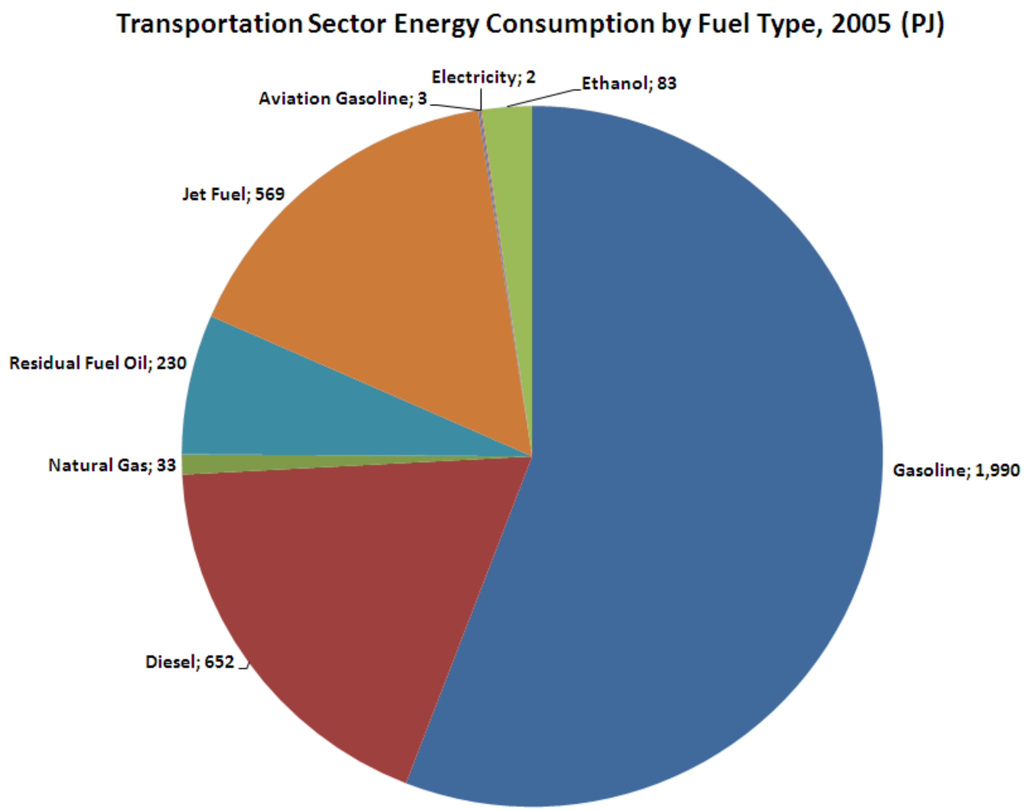



**Figure 9  Transportation Sector Final Energy Consumption by Fuel Type, 2005**

Like the other end-use sectors, transport is far from being a homogenous category.  It is comprised of a number of distinct subsectors, each of which fulfills a unique role within California's energy economy.  Perhaps not surprisingly, the most used transport fuel is gasoline (Figure 9), and the largest subsector is light-duty vehicles (Figure 10).  Light-duty passenger cars and trucks account for a little more than half of all transport energy consumption in California.  The other on-road subsectors (motorcycles, medium- and heavy-duty trucks, and buses) contribute an additional ~15%, while the aviation and marine subsectors comprise almost a quarter of all transport sector energy consumption. Off-road and construction devices, agricultural vehicles, and pipelines makes up the final ~6%.

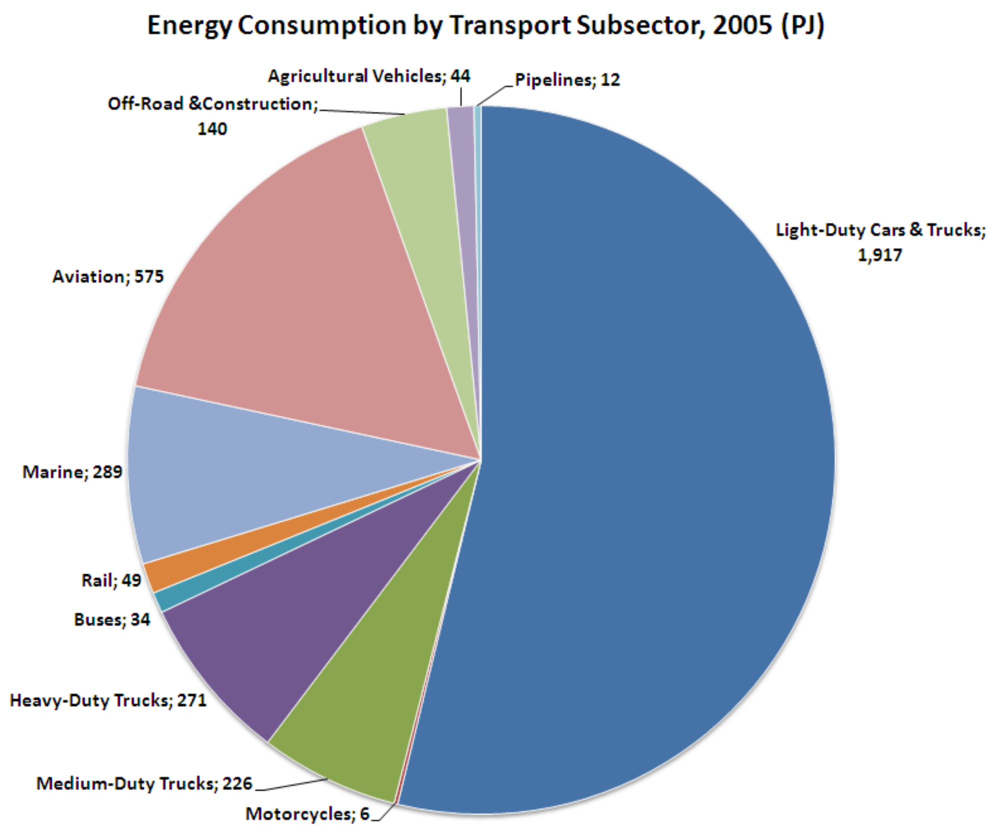



**Figure 10  Final Energy Consumption by Transport Subsector, 2005**

The fuel use estimates shown in Figure 10 include all energy consumption for any vehicles that purchase fuel within California, regardless of the destination of the trip – whether it be intrastate (within the state), interstate (to another state), or international (to another country). By this definition, the fuel consumption of a vehicle that starts its trip in another state or country and then terminates in California is not included, an issue that principally concerns the aviation and marine subsectors and is important because, in a relative sense, the vast majority of California's aviation and marine activity crosses state borders. It is also important from a policy perspective. Following guidelines published by the Intergovernmental Panel on Climate Change (IPCC), the California Air Resources

Board (CARB) calculates, but excludes, fuel use and GHG emissions resulting from aviation and marine fuel purchased in California and used for interstate and international trips (CARB, 2009a). Therefore, the energy and emissions estimates provided in this chapter will appear higher than those published by CARB in its official Greenhouse Gas Inventory. In order to do a fair comparison, when using the CARB numbers, one should make sure to add back in the energy and emissions estimates from their so-called "Excluded Emissions" category.

The reason I have chosen to include all transport activity, energy, and emissions in the estimates presented in this chapter, as well as in the CA-TIMES model itself, is quite simple: my objective is to model the entire California energy system, both present and future, in an effort to develop deep GHG reduction scenarios that allow the state to meet its long-term energy and environmental goals. While the policy process of today may not clearly specify which regulatory entities will eventually have jurisdiction over aviation and marine trips that cross state/country boundaries, it is quite likely that if a dramatic transformation of California's energy system is to ultimately take place, none of the state's energy sectors or subsectors can afford to be ignored. Therefore, I have made sure not to ignore them in my modeling.

### *II.1.2 Electricity Generation*

The electricity sector is similar to oil refineries, bio-refineries, and hydrogen production facilities, in that power plants take a primary energy feedstock (e.g., natural gas, biomass, uranium, wind, hydro, coal) and convert it into a finished fuel product, in this case electricity, which can then be delivered and consumed within one of the five end-use sectors (industrial, commercial, residential, agricultural, and transportation). For this reason, these conversion facilities are often said to be a part of the "secondary" energy sector, where the "primary" sector refers to, for example, oil and natural gas production, coal and uranium mining, and biomass feedstock collection.

A variety of power plant types are used to produce electricity for the California market, the so-called "generation mix" (Figure 11). Natural gas, which actually encompasses several different plant technologies (combined-cycles, steam turbines, and gas turbines), is used to supply almost half of all electricity that is generated within California. The next largest categories are hydropower and nuclear, respectively. Production from other renewable and non-renewable sources comprises the remainder of in-state generation. However, a large share of California's electricity is actually supplied from outside the state. In fact, if it were classified as its own generation type, imports would represent the single largest source of electricity supply for California. In reality, imports are generated from a variety of fuel sources, and there are two different types of imports: firm and system. Firm imports refer to generation from power plants located outside of California but owned by in-state utilities (e.g., Pacific Gas & Electric, Southern California Edison, San Diego Gas & Electric). At present, these utilities operate plants that are located in Oregon, Arizona, Nevada, New Mexico, and Utah. System imports, on the other hand, refer to electricity produced by utilities in the Pacific Northwest (Oregon and Washington) or Desert Southwest (Arizona and New Mexico) that is only imported when available or needed – essentially the spot market for electricity. Because of fluctuating electricity demand and supply and annual rainfall levels (which impacts hydro availability), both within California and in these other states, the mix of imports changes from year to year. Figure 12 shows what the import mix looked like in 2005. Natural gas, hydro, and coal are the main fuel sources. Note that, although not shown, firm imports accounted for ~40% of the import total in 2005, while system imports made up the rest. (As discussed in a later section, Ryan McCarthy's dissertation is the source of most of the historical electricity sector data shown here and input to the CA-TIMES model for calibration between 2005 and 2010 (McCarthy, 2009).)

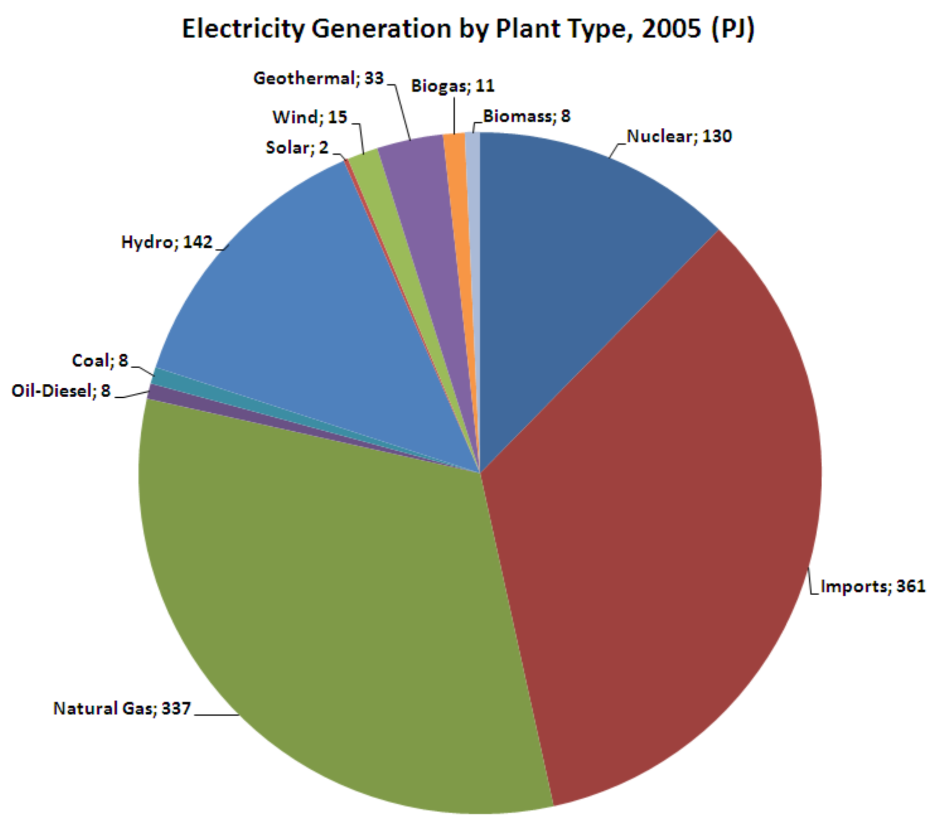



**Figure 11  Electricity Generation by Plant Type, 2005**

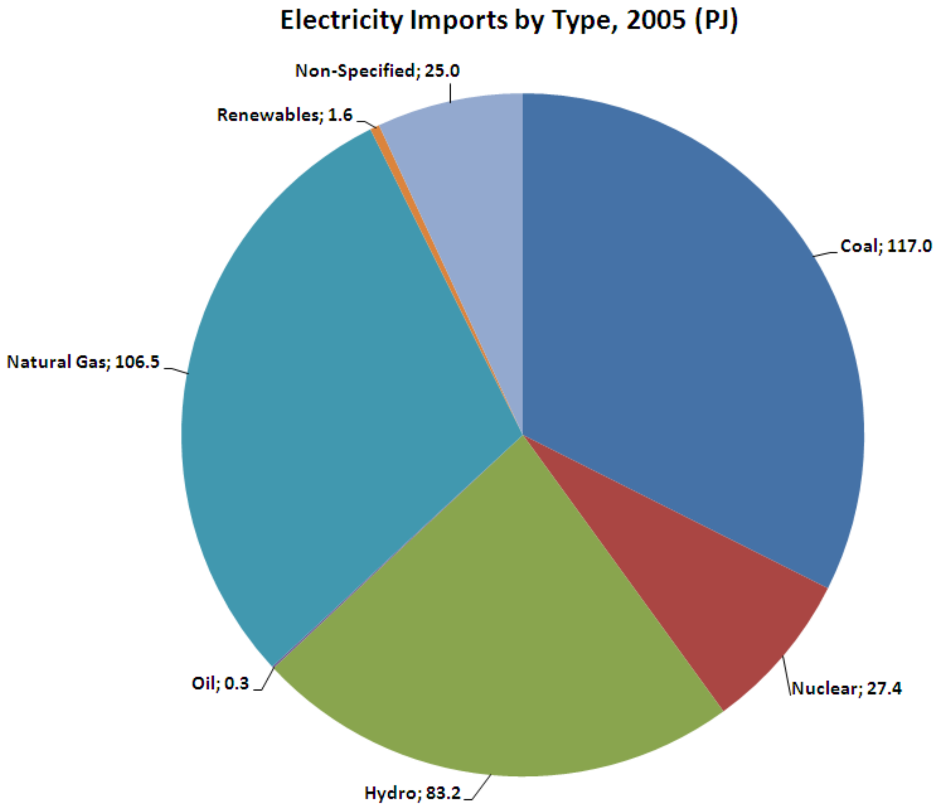



**Figure 12  Electricity Imports by Type, 2005**

Continuing a previous discussion, it is interesting to note that, as required by the Global Warming Solutions Act of 2006 (AB 32), the energy use and emissions related to electricity imports *are* included in CARB's official GHG Inventory (CARB, 2009a). Thus, in the CA-TIMES model and in the data and results presented in this chapter, I also follow this same convention, attributing energy and emissions from electricity imports to the CA-Combustion in-state category.

### *II.1.3   Greenhouse Gas Emissions*

California greenhouse gas emissions are a by-product of fuel combustion in the electricity, refining, transport, industrial, commercial, residential, and agricultural sectors, as well as due to a host of other non-fuel combustion activities, including, but not limited to, industrial processes (e.g., cement and lime production, manufacturing of electronics equipment), livestock enteric fermentation and manure management, forest lands, crop burning, solid waste disposal and wastewater treatment, to name just a few (CARB, 2009a). This non-fuel combustion (i.e., non-energy) category partly includes high-GWP (Global Warming Potential) gases, such as hydrofluorocarbons (HFC), halocarbons, and sulfur hexafluoride (SF6). In addition, a small, but non-significant quantity of GHG emissions are annually sequestered (i.e., stored) in California's vast forests and rangelands.

According to the California Air Resources Board's official GHG Inventory (CARB, 2007a, 2010a), the state's total emissions of greenhouse gases from all sources amounted to 518 million tonnes carbon dioxide-equivalent (Mt $CO_2$-eq) in 2005, a figure that was up 6.7% from 486 Mt in 1990 (Figure 13). These totals include emissions from interstate and international aviation and marine activity, what CARB refers to as "Excluded" emissions, a category that contributed 59 and 45.5 Mt $CO_2$-eq in 1990 and 2005, respectively. Also included in the official CARB statistics are non-energy GHGs, which contributed 35.8 and 55.4 Mt $CO_2$-eq in 1990 and 2005, respectively.

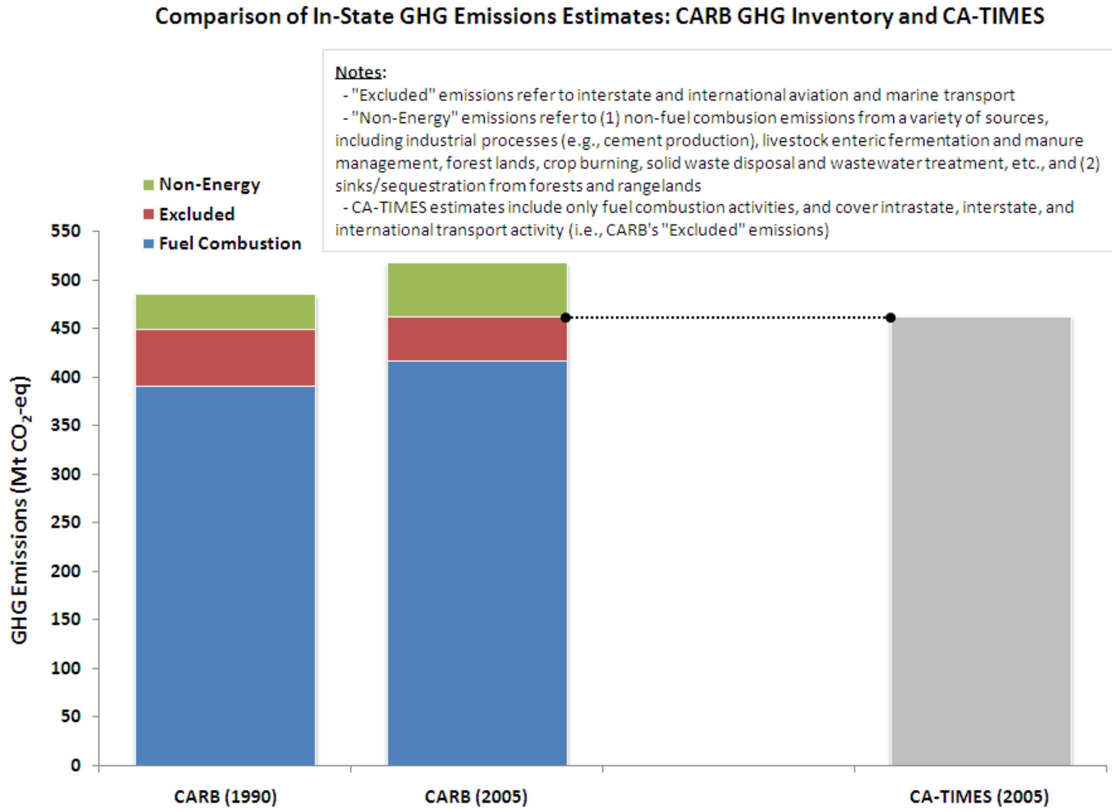


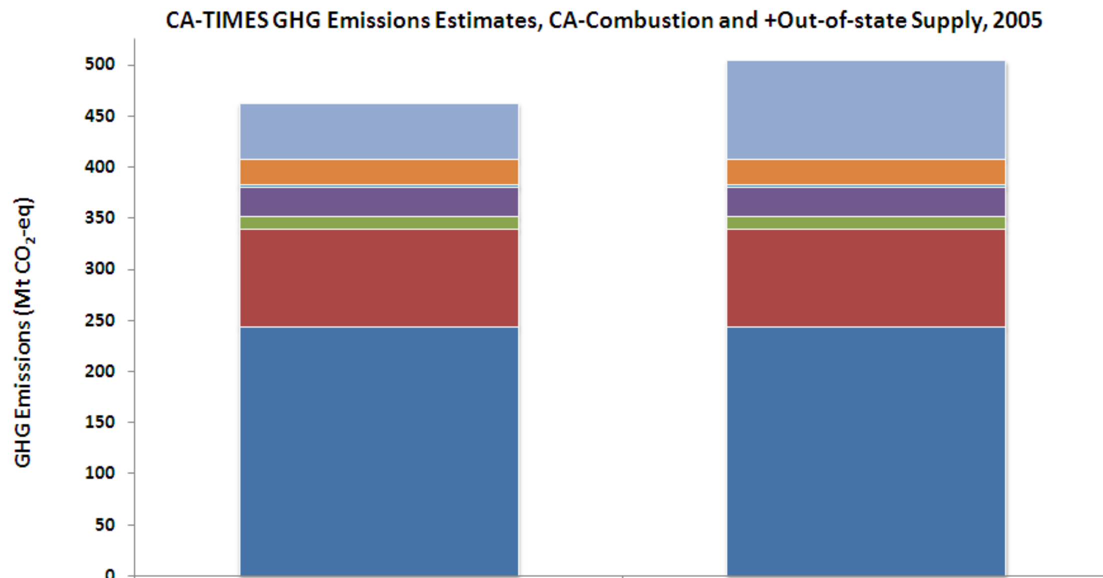

**Figure 13 Comparison of GHG Emissions Estimates: CARB GHG Inventory and CA-TIMES**

Unlike the CARB GHG Inventory, the current version of the CA-TIMES model only covers emissions from fuel combustion activities. Non-energy GHGs (which accounted for just 11% of total emissions in 2005) are not modeled at the present time, though there are plans to do so at a later date by other members of our research team. Moreover, as discussed earlier in this chapter, the model covers intrastate, interstate, and international aviation and marine activities. Therefore, the emissions estimates from CA-TIMES are directly comparable to the sum of the "Fuel Combustion" and "Excluded" emissions categories from the CARB GHG Inventory. Figure 13 clearly illustrates this comparability and at the same time indicates how closely the CA-TIMES model (comprised of hundreds of technologies – each with unique fuel inputs, efficiencies, and costs – which are spread over the various primary, secondary, and end-use energy sectors) is able to replicate the energy system of California in the base-year 2005. The statistical difference between the CA-TIMES model output and the 2005 data is less than 0.1%. In total, the current version of the CA-TIMES model captures 89% of all GHG emissions currently produced by the California energy system. Such broad coverage becomes especially important when developing deep GHG reduction scenarios, since the emissions reductions required in the future depend in large part on the historical baseline.

Given that California's transportation sector is the single largest energy-consuming category in the state, as discussed previously, it is perhaps not surprising that transport is also the greatest emitter, comprising a little more than half of all greenhouse gas emissions in 2005 (Figure 14). The second largest polluter is the electricity sector, followed by the combined industrial/supply sector. The residential, commercial, and agricultural sectors emit relatively low quantities of GHGs since electricity makes up such a large share of fuel consumption in each of these sectors, and emissions from electric generation are accounted for in the "Electricity" category in Figure 14. Viewed another way, Figure 15 allocates electric sector emissions to the various end-use sectors – i.e., each end-use sector is assigned an additional quantity of emissions in proportion to the share of electricity it consumes in total economy-wide production. The sectors most affected by this allocation are residential, commercial, agricultural, and industrial. Because the transport sector in California only consumes a small amount of electricity at present (mostly for rail and certain bus applications), its emissions are essentially unchanged. Note that because the transport, electricity, and supply sectors account for

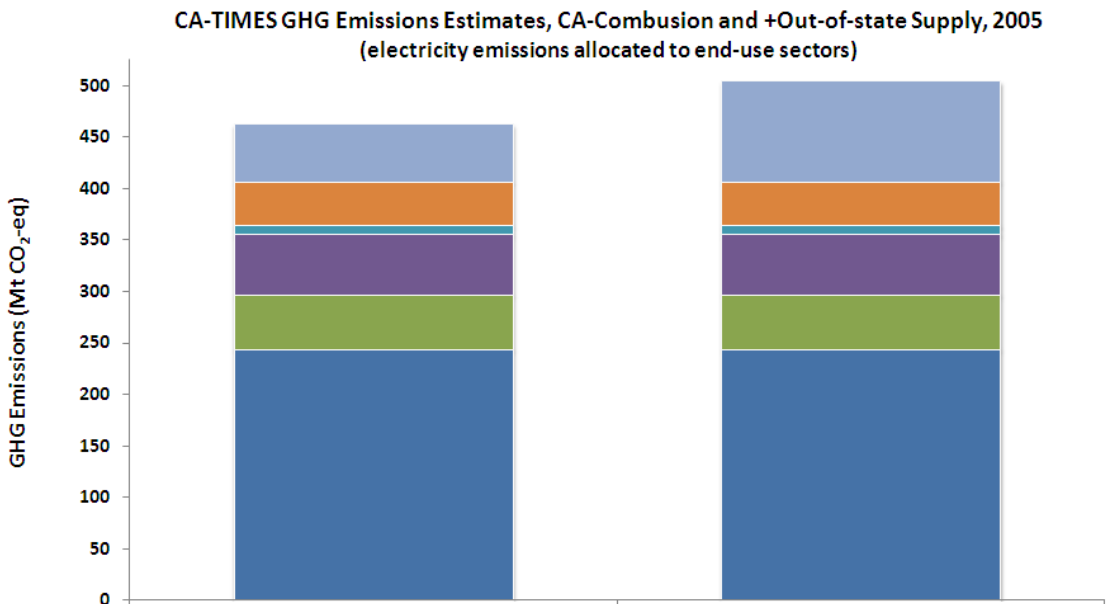
85% of all emissions related to fuel combustion, these are the sectors that receive the most attention in this dissertation and are, thus, modeled with the greatest bottom-up technological detail in the current version of the CA-TIMES model.

At this point, the reader should note a small, but important, accounting detail that concerns industrial and supply sector emissions. Officially, there is no "Supply" category in the CARB GHG Inventory. Within the CA-TIMES modeling framework, however, the supply sector covers certain industrial activities, including petroleum refining, oil and gas extraction and production, biomass feedstock collection and transport, coal and uranium mining, and delivery of finished fuel products; in future model years, bio-refineries, hydrogen production facilities, and a few other types of conversion plants are included as well. Therefore, the combined industrial/supply category in CA-TIMES is synonymous with the conventional meaning of the "Industrial" sector, as might be found in the CARB GHG Inventory or elsewhere. Naturally, care has been taken not to double-count energy use and emissions in the industrial and supply sectors of CA-TIMES.




| | CA-Combustion | +Out-of-state Supply |
|---|---|---|
| Supply | 54.4 | 96.2 |
| Industrial | 25.7 | 25.7 |
| Agricultural | 1.6 | 1.6 |
| Residential | 28.8 | 28.8 |
| Commercial | 12.6 | 12.6 |
| Electricity | 95.6 | 95.6 |
| Transportation | 243.6 | 243.6 |

**Figure 14 CA-TIMES GHG Emissions Estimates, CA-Combustion and +Out-of-state Supply, 2005**




| | CA-Combustion | +Out-of-state Supply |
|---|---|---|
| Supply | 55.8 | 97.6 |
| Industrial | 42.3 | 42.3 |
| Agricultural | 8.3 | 8.3 |
| Residential | 59.0 | 59.0 |
| Commercial | 53.1 | 53.1 |
| Transportation | 243.9 | 243.9 |

**Figure 15 CA-TIMES GHG Emissions Estimates, CA-Combustion +Out-of-state Supply, 2005 (electricity emissions allocated to end-use sectors)**

Figure 14 and Figure 15 both show two types of emissions estimates, *CA-Combustion* and *+Out-of-state Supply*. CA-Combustion emissions are fairly self-explanatory: they include all emissions produced from fuel combustion activities within the boundaries of California's energy system, which in this analysis is defined to also include emissions from interstate and international aviation and marine trips whose origin is California and from all power plants whose electricity is destined for the California market, even if those plants are located in neighboring states. (The latter procedure is consistent with the CARB GHG Inventory, wherein only the "California share" of emissions from electricity imports is counted.) For the base-year 2005, the CA-Combustion designation does not include emissions that result from transporting primary energy feedstocks (e.g., crude oil, natural gas, coal, uranium, biomass) or finished fuels (e.g., refined petroleum products, biofuels) from outside of the state into California, nor are the upstream lifecycle ("well-to-tank") emissions resulting from production/conversion of these feedstocks/fuels outside of California considered, except for combustion emissions related to electricity imports. Nevertheless, from a modeling standpoint, it would be quite useful to be able to calculate the full lifecycle GHG emissions (both "well-to-tank" and "tank-to-wheel") for all of the fuels consumed within the California energy system, including emissions from the upstream supply stages that occur outside the state or even in another country (e.g., crude oil production in the Middle East). For this reason, the CA-TIMES model also tracks the vast majority of upstream emissions related to imported energy commodities and assigns these out-of-state emissions to the *+Out-of-state Supply* emissions total. In particular, the emissions are allocated to the supply sector category. The upstream emission factors for each type of resource/fuel generally come from the California-specific version of Argonne National Laboratory's Greenhouse gases, Regulated Emissions and Energy Use for Transportation (GREET) Model (CARB, 2007b). Figure 14 and Figure 15 illustrate that total emissions including out-of-state supply are, as expected, slightly larger than CA-Combustion emissions in the base-year 2005. This is due entirely to total supply sector emissions being about 75% greater than in the CA-Combustion case. In other words, a large portion of the upstream emissions that are generated while producing final energy carriers for end-use consumption in California actually occur outside of the state's borders. Emissions from the non-supply sectors are, by definition, the same in both the CA-Combustion and +Out-of-state Supply cases. Therefore, one should not think of the figures as showing the well-to-wheel emissions of each energy sector. This calculation would require the careful allocation of total supply and electric sector emissions to each of the end-use demand sectors, which incidentally has been done separately, as discussed below.

The average lifecycle carbon intensities of several fuels commonly used in California in 2005 are shown in Figure 16 (technically speaking, electricity is an energy carrier). Both upstream (well-to-tank) and fuel combustion (tank-to-wheel) emissions are highlighted. The carbon intensities of the refined petroleum product fuels (gasoline, diesel, residual fuel oil, and jet fuel) are roughly similar, ranging from 78 to 88 $gCO_2$-eq/$MJ_{HHV}$, with most of their emissions being attributable to the fuel combustion stage. Natural gas is less carbon-intensive than these fuels; in fact, natural gas is the least carbon-intensive of all commonly used fossil fuels. Interestingly, the most carbon-intensive fuel shown in the figure is electricity (based on California's average grid mix), whose emissions are attributed entirely to the upstream stages, because electricity is not actually combusted. One must keep in mind, however, that electric motors tend to be more efficient energy conversion devices than internal combustion engines, boilers, and gas turbines (efficiencies can be up to four times greater). Therefore, the true carbon intensity of electricity is actually quite a bit less than the other fuels shown, if one takes as the boundary the useful work (i.e., energy service) that is supplied by an energy conversion device.

In comparing the fuel carbon intensities shown here to those of other studies, it is important to note that I estimate all carbon intensities on a higher heating value (HHV) basis. (In fact, all energy flows in CA-TIMES are estimated on a HHV basis.) Utilization of a HHV for a fuel's heat content (in units of, say, MJ/gal) has the effect of lowering a carbon intensity estimate on a lower heating value (LHV) basis by about 7 to 11%, depending on the particular fuel (except for electricity, of course, for which LHVs and HHVs are the same). This is important because the convention adopted by the GREET model, the California Low Carbon Fuel Standard (LCFS) regulations, and most other lifecycle analysis studies is to use a LHV basis for estimating fuel carbon intensities. Our research group has chosen to adopt a HHV basis throughout the CA-TIMES model because it represents a more accurate treatment of energy flows (from primary resource supply through conversion to end-use) and because it is the approach adopted by the U.S. Energy Information Administration (EIA) in its National Energy Modeling System (NEMS) energy forecasting and scenarios model.

Taking this LHV/HHV conversion issue into account, the average lifecycle carbon intensities calculated within the CA-TIMES framework match up quite well to what one would expect to see, based on other studies. In truth, the CA-TIMES values are a little on the low side, if only slightly, say by about 2% to 4%. This is due to inherent limitations with trying to capture every single process and emission flow related to the lifecycle production of a particular resource/fuel commodity. Entire careers have been devoted to developing modeling tools to do just that (e.g., Argonne's GREET and Delucchi's LEM). The lifecycle analysis (LCA) model used in conjunction with CA-TIMES is simply an Excel-based tool that I developed (somewhat tangentially to the core model development), in order to post-process the results produced by CA-TIMES. The tool takes the output of a given CA-TIMES model run/scenario and allocates all of the energy and emission flows to the various production stages for the numerous fuel products. Great care is taken to apportion these flows in the correct way. The LCA calculations definitely do *not* occur internally within the current version of the CA-TIMES model, which is a very important point since this limits one's ability to impose dynamic constraints on carbon intensities while the model is running, something that might be desirable if one were to want to analyze an LCFS policy. Future work by other members of the CA-TIMES research team may attempt to address this important limitation of the model. In any case, various other types of energy and environmental constraints can be feasibly implemented within the model framework, including carbon caps, vehicle fuel economy standards, renewable portfolio standards, and so on (as discussed in greater detail in later sections).

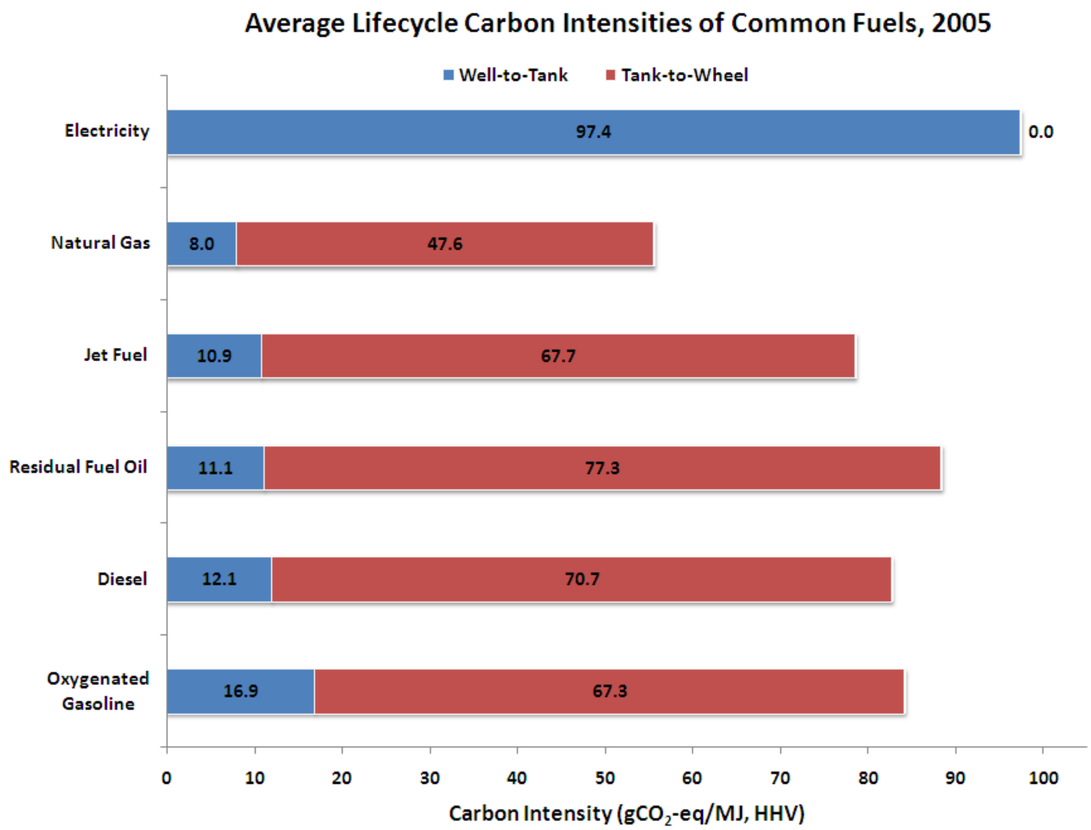



**Figure 16 Average Lifecycle Carbon Intensities of Common Fuels, 2005**

By comparison, California's energy system is less carbon-intensive than other US states and other countries. For instance, as shown in Figure 16, the CA-TIMES model estimates that the average carbon intensity of California's electricity grid – taking transmission line losses into account – was 97.4 $gCO_2$-eq/MJ (351 $gCO_2$-eq/kWh) in 2005, a value confirmed by McCarthy (2009). This is significantly less than U.S. average electric generation, which achieved a carbon intensity of 170 $gCO_2$-eq/MJ (612 $gCO_2$-eq/kWh) in 2005 (EIA, 2006; EPRI, 2007). The reason for this large difference is fairly straightforward: the vast majority of California's electricity comes from relatively low-carbon sources, such as nuclear, hydro, natural gas, and other renewables, whereas a significant portion of US electric generation (~50%) is derived from coal power.

Other similar metrics also indicate that California's economy and energy system are less carbon-intensive than the rest of the country. Table 6 presents California GHG emissions relative to the state population and the state's gross domestic product (GDP/GSP) in 1990 and 2005. For comparison, average values for the U.S. are shown as well. The emissions estimates shown here include all types of in-state GHGs (or in the case of the U.S., all domestic GHGs), i.e., emissions from fuel combustion, non-energy emissions, and forestry/rangeland sinks, etc. that occur within California, excluding interstate and international aviation and marine emissions. The statistics show that the carbon intensity of California's economy has decreased significantly since 1990. In fact, California was less carbon-intensive in 1990 than the entire U.S. was fifteen years later in 2005.

**Table 6 Indicators of Economy-Wide GHG Emissions in California and the U.S.**

| | California | | United States* | |
|---|---|---|---|---|
| **Year** | **1990** | **2005** | **1990** | **2005** |
| **$tCO_2$-eq per Mill$ GDP** | 477 | 305 | 640 | 490 |
| **$ GDP per $tCO_2$-eq** | 2,097 | 3,281 | 1,563 | 2,040 |
| **$tCO_2$-eq per capita** | 17.4 | 14.0 | 19.9 | 20.1 |

Data sources: CARB (2007a), CARB (2010a), UN (2010)*

* *Notes: U.S. emissions estimates are taken from the United Nations Framework Convention on Climate Change (UNFCCC) statistics, rather than from the Carbon Dioxide Information Analysis Center (CDIAC)*

## II.2 Methodology

The model developed in this project has been named CA-TIMES. It is a technologically-rich, integrated energy-engineering-environmental-economic systems model that is a variant of the MARKAL and TIMES family of energy models, focusing on the California energy system and containing California-specific data and assumptions.[14] CA-TIMES is a unique simulation tool, in that it will represent the first publicly available model of its kind in the state, when it is fully developed. Unlike other economic models that have previously been used for California energy and climate policy analysis[15], CA-TIMES is a bottom-up, optimization model, which covers all sectors of the California energy economy, including primary energy resource extraction, imports/exports, electricity production, fuel conversion, and the residential, commercial, industrial, transportation, and agricultural end-use sectors. Over the next several years, CA-TIMES will be used by UC-Davis researchers and the California Air Resources Board to generate and analyze scenarios for meeting California's long-term (2020-2050) GHG emission reduction goals. My dissertation work begins this process by performing scenario analyses, evaluating policy, and presenting technological portraits for the future given the specific conditions that exist within the state.

[14] An alternative way of viewing MARKAL and TIMES is that they are model "shells". We take this shell, which contains hundreds of embedded equations and algorithms, and input the data for California, thereby creating a California-specific energy systems model. In this sense, the modeling is data-driven, and we avoid wasting excessive time tinkering with the model code.

[15] For example, the Energy 2020 model by Systematic Solutions; an electricity and natural gas sector model by Energy and Environmental Economics (E3); and the Environmental Revenue Dynamic Assessment Model (E-DRAM) by UC-Berkeley, California Department of Finance, and CARB.

### *II.2.1 Solution Framework of the CA-TIMES Model*

The MARKet ALlocation (MARKAL) model and its next-generation extension, The Integrated MARKAL-EFOM1 System (TIMES), are comprehensive energy-engineering-environmental-economic (so-called "4E") modeling frameworks used by the U.S. DOE National Laboratories, the U.S. DOE Energy Information Administration (EIA), the U.S. Environmental Protection Agency (EPA), the International Energy Agency (IEA), and most UNFCCC Annex I governments. In fact, over the past 30 years, MARKAL-TIMES models have been utilized by more than 250 institutions in some 70 countries worldwide (Goldstein, 2009). While there are at present two national-level U.S. MARKAL models used for government energy forecasting and analysis, there are none, quite surprisingly, that are specific to the state of California. In fact, there are no publicly available bottom-up energy-engineering-environmental-economic models that cover all sectors of the state's energy system. As California moves forward with a broad spectrum of carbon emissions reduction policies, there is a strong need for this kind of transparent, flexible, and accessible analysis tool to help inform policy decisions.

MARKAL-TIMES models are partial-equilibrium models that solve iteratively in GAMS (General Algebraic Modeling System) via optimization of an objective function (Loulou et al., 2005).[16] The standard solution method is linear programming (LP), though mixed-integer and stochastic programming are also possible. An interior point solver using CPLEX or XPRESS is normally chosen. The objective of a typical model is to supply energy services at minimum global cost (or more accurately, at minimum loss of consumer and producer surplus, by reaching a supply-demand equilibrium with

[16] Documentation of the TIMES model framework can be found at http://www.etsap.org/documentation.asp

endogenous energy service demands)[17] subject to a larger set of technical and policy constraints (Figure 17, Figure 18).[18] Importantly, the technological supply curves in TIMES are not assumed by the modeler; rather, they are built endogenously within the model. The modeler inputs a host of data and assumptions for individual technologies, and then TIMES implicitly constructs the supply curves internally. These supply curves are not fixed in any given time period and/or across different model runs: rather, they shift and vary, as the model continuously makes decisions in an effort to maximize total consumer and producer surplus. Demand curves, on the other hand, may be input exogenously by the modeler or built endogenously within the model, depending on whether the demand commodity in question is an energy service demand or energy carrier or material. In the latter case (e.g., for a fuel such as gasoline), it is not necessary for the modeler to specify an exogenous demand because the demand for the commodity will be calculated endogenously within TIMES – i.e., TIMES chooses whether or not to consume the fuel/material based on whether or not it is a cost-effective to do so from a *systems level* perspective. In the case of energy service demands (e.g., for light-duty vehicle-miles traveled), either the modeler exogenously specifies a demand trajectory for each year of the model time horizon or she specifies a demand trajectory and in addition a constant own-price elasticity for the demand in each year.[19] In the latter case, the TIMES model internally constructs a demand function, using the demands and elasticities as

[17] Total surplus is maximized at the point where the quantities and prices of the model's various commodities (energy carriers, demands, materials, and emissions) are in equilibrium, i.e., their prices and quantities in each time period are such that the suppliers produce exactly the quantities demanded by the consumers.

[18] The basic equations of the model are commodity balances, transformation equations, input/output shares on process flows, activity definitions, utilization constraints, and market share constraints.

[19] An own-price elasticity of demand is a measure of the responsiveness of the quantity demanded of a good or service to a change in its price. It is typically represented as a percentage change in quantity demanded in response to a one percent change in price (holding constant all the other determinants of demand, such as income).

inputs. Note that if the modeler specifies fixed demands (not demand functions), then the optimization problem is essentially transformed from the maximization of total consumer and producer surplus to the minimization of total system costs. In this situation, the model becomes more of a supply model, as its ability to flexibly adjust demands is reduced. Figure 19 diagrammatically illustrates the alternative supply-demand equilibrium in TIMES when fixed energy service demands are exogenously specified by the modeler. The capability of specifying elastic demands is a special feature of MARKAL-TIMES models; however, not all modeling groups choose to run their models in "elastic mode" due to the problems that can potentially arise if reliable elasticity data is not able to be found for all demands of interest.

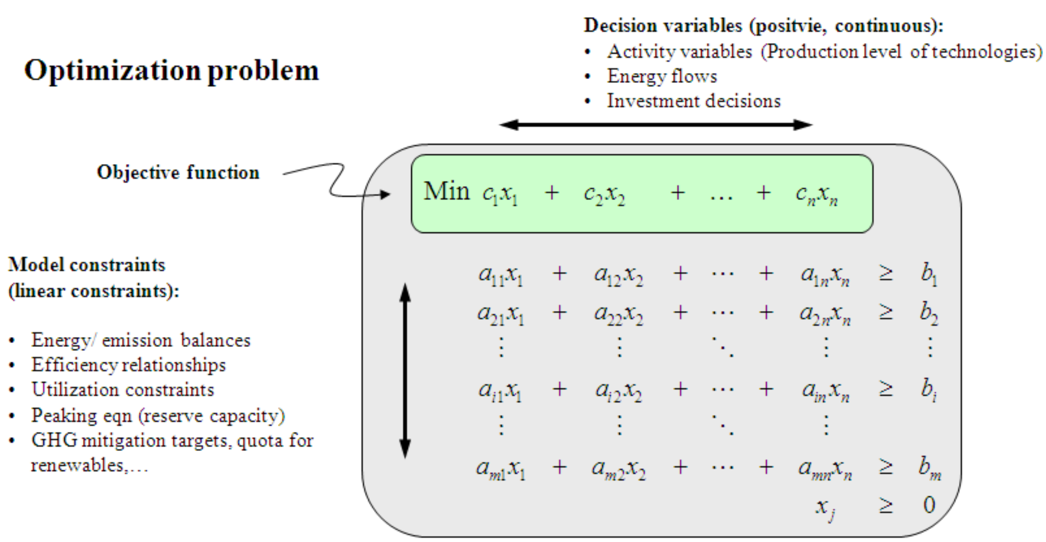



**Figure 17 Simplified Representation of the Linear Programming Optimization Problem in TIMES**
* *Figure source: Uwe Remme, University of Stuttgart and International Energy Agency*

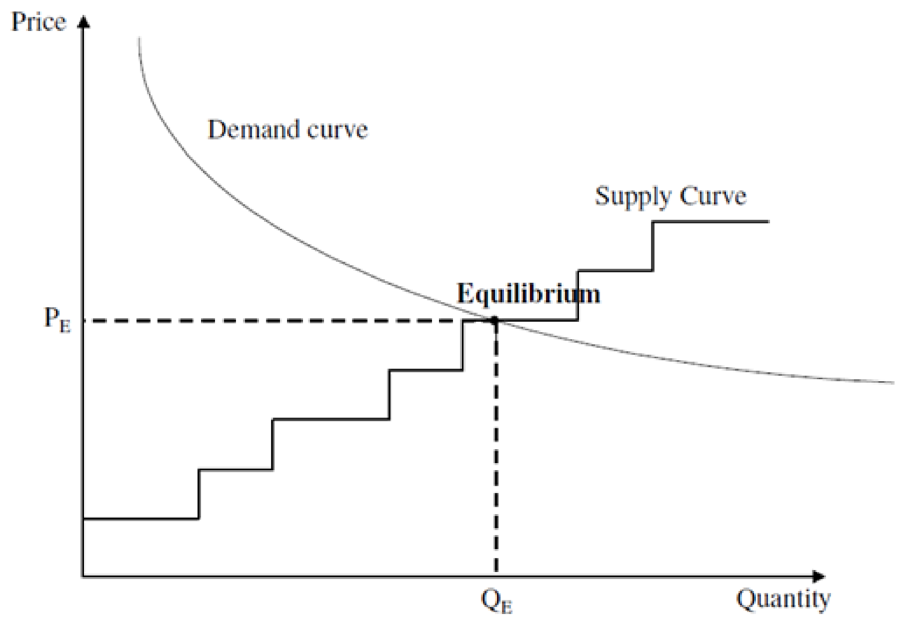



**Figure 18 Supply-Demand Equilibrium in TIMES for an Endogenous Energy Carrier, Material, Emission, or Service Demand**
* *Figure source: Loulou et al. (2005)*

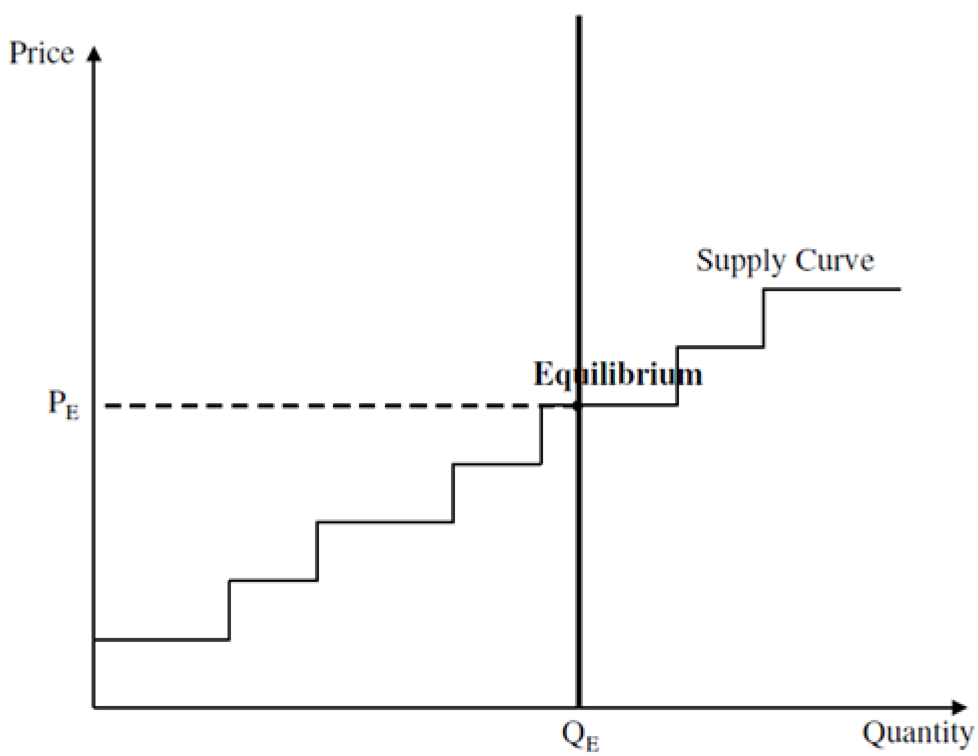



**Figure 19 Supply-Demand Equilibrium in TIMES for an Exogenous Energy Service Demand**
* *Figure source: Loulou et al. (2005)*

The TIMES objective function sums the discounted net present values (NPV) of capital costs, fixed and variable O&M, import and export costs, delivery costs, taxes and subsidies, salvage values, and welfare losses (resulting from reduced end-use demands), as well as other cost terms, for all years and regions within the model.[20] Basically, the consumption and production of every demand, energy carrier, material, and emission within the model has a cost associated with it – all vehicles, fuel conversion devices, and power plant technologies, all primary energy resources, and so on – and the total discounted NPV of these costs is minimized. In doing so, the model attempts to replicate the kind of rational economic behavior that, in theory, we should see exhibited by consumers and firms in a perfectly competitive market. Of course, in reality many markets are imperfect (e.g., consumers of private transportation, oil suppliers, etc.), and consumers and firms often exhibit irrational behavior from purely an economic perspective (when considering only private costs). It, therefore, becomes necessary to depart from the perfectly competitive market framework, and this is possible in TIMES through the introduction of taxes, subsidies, and explicit user-defined constraints (e.g., limits to technological growth and penetration, constraints on emissions, technological hurdle rates, demand elasticities, etc.).

A strongpoint of MARKAL-TIMES models is that they have the capacity to represent technologies in considerably rich, bottom-up detail, thereby allowing for the characterization of energy system dynamics over a long-term, multi-period time horizon

[20] A global discount rate of 4% is used in the CA-TIMES model. However, certain process have technology-specific discount rates (i.e., hurdle rates), which may be considerably higher.

(e.g., from 2005 to 2050). A given model contains a large database with hundreds to thousands of technologies, and each technology is characterized by technical, financial and environmental parameters (e.g., efficiencies, capital and O&M costs, and emissions factors). These databases are written in Excel spreadsheet tables and are, thus, easily accessed and transferable. Technological progress[21] is accounted for in the model, and the future availability of new, advanced technologies is considered. The main decision variables are investment choices (e.g., new capacities, extension, and retirement) based on annualized costs (capital, variable, fuel, O&M, and emissions prices), activities, energy/emission flows, storage, demand, and trade. Shadow prices of the decision variables, representing the marginal system values of the constraints, are determined by the dual equations. Note that in the TIMES model, demands can be decision variables as well, if they are specified to depend on energy prices (i.e., if they have elasticities associated with them).

The current version of CA-TIMES can be described as a perfect foresight model with a single decision-maker (sometimes referred to as the "social planner"). The model has perfect information over the entire model planning horizon and complete knowledge of the market's parameters, both now and in the future. In other words, the model knows in 2010 what the total electricity demand and cost of a particular power plant will be in 2030, 2040, and 2050; therefore, it can make the best possible investment and operating decisions in each year, in order to optimize costs over the entire model time horizon.

[21] Technological progress is captured via exogenous specification of future technology cost and performance assumptions, investment in new technologies, and early retirement of inefficient technologies. The model also has the potential to represent technological progress endogenously through learning and experience curves (i.e., a progress ratio approach), although the current version of the CA-TIMES model does not make use of this feature.

Alternately, a non-standard, myopic version of the TIMES model also exists, though I have chosen not to use it for the purposes of my dissertation. (The myopic version may be used in the future by other members of the research team.) Perfect foresight models are preferred for scenario development and when conducting so-called “what if” exercises because they allow a researcher to answer questions, such as, “What is the best way for society to get from where we are today to where we want to be in the future?” Myopic models, in contrast, are typically used for forecasting and predicting and are better geared to answer questions such as, “What is likely to happen in the future given current policies and how we think energy prices and technologies will develop over time?” While the differences between these two modeling approaches may be subtle, they are nevertheless important.

**Box 1**
*In layman’s terms: How CA-TIMES makes fuel use and investment decisions*

This box provides a straightforward explanation of how the CA-TIMES model makes its fuel use and investment decisions, hundreds of thousands of which are made in parallel during a single model run. Supply of light-duty car demand over the multi-period time horizon is taken as an example.

First, the modeler specifies an exogenous trajectory of light-duty car demand (in units of vehicle-miles traveled) over the next several decades. These growth projections are typically taken from other studies or official government forecasts. The model can choose to meet this demand in a number of different ways. For instance, it can choose to invest in gasoline internal combustion engine (ICE) vehicles or hybrid-electric vehicles (HEV), diesel ICEs or HEVs, biofuel ICEs or HEVs, battery-electric vehicles (BEV), hydrogen fuel cell vehicles (FCV), or a number of other options. It can also choose some combination of all these vehicle types. The decision criterion for investment is the vehicle-fuel combination with the lowest total discounted net present value cost over its entire life (say, 15 years). The costs considered are the annualized stream of capital costs, fuel costs, and variable and fixed O&M costs. However, some of the more advanced vehicle technologies are quite unfamiliar to consumers; thus, there is a certain risk associated with them. This manifests itself as a cost premium and is formulated in the model as assigning a higher hurdle rate (i.e., technology-specific discount rate) to these advanced technologies.

While the investment cost of each of the vehicle technologies is exogenously specified by the modeler for each year of the model (typically, by using results from techno-economic studies as a basis for the assumptions), the fuel costs are constantly varying, as the model solves for them endogenously using supply curves that it calculates internally. These curves depend on (1) the cost of the technologies supplying the particular fuels (e.g., oil refineries, bio-refineries, hydrogen production facilities, electric generation plants), and (2) the cost of primary energy resources that are fed to the fuel conversion sector. The cost trajectories of each of the electric generation and fuel conversion technologies are exogenously specified by the modeler for each year of the model (unless the endogenous technological learning function is used), and the costs and quantities of the various primary energy resource commodities (e.g., coal, oil, natural gas, uranium, biomass, and imports of finished fuel products) are represented with supply curves or price trajectories for future years. As before, common practice is for these input assumptions to be based on the findings of other reliable studies.

Here, one can begin to see the indirect link between investment and fuel use decisions in seemingly unrelated sectors, such as transport and electric generation. For instance, the decision of whether or not to invest in a BEV depends on the full lifecycle costs of this technology, which itself depends, at least in part, on how much it costs to install new electric generation and transmission capacity and, if there is a carbon cap or tax, the carbon intensity of the electricity that is produced. The decision to install new generation capacity depends on the demand for electricity in each of the other end-use sectors and the cost of primary energy resources that are consumed to generate the electricity. Similar decisions are continuously being made for other types of light-duty car technologies, as well as all of the other technologies in the other transport subsectors and the electricity, supply, industrial, commercial, residential, and agricultural sectors. The ability to represent a multitude of simultaneous decisions across a wide range of sectors is at the heart of *systems level* modeling, and this is certainly what makes it an attractive and useful tool for conducting energy analyses.

### *II.2.2 CA-TIMES Reference Energy System*

The concept of the Reference Energy System (RES) is fundamental to the craft of energy systems modeling. The RES describes the entire structure and network of a particular system via three types of entities (Loulou et al., 2005):

- Technologies: these encompass all technologies including mining, import, export, fuel conversion, electric generation, transportation, and other end-use demand technologies;
- Commodities: these consist of energy carriers, energy services, materials, monetary flows, and emissions.
- Commodity flows: these are the links between processes and commodities.

The CA-TIMES RES represents California's energy system as it exists today, and it provides full descriptions for potentially available technologies, energy resource potentials, and service demands for future years out to 2055. The energy flows and energy balances are calibrated to 2005, and then optimized for all future years (generally at 5-year time steps). The RES essentially connects all processes (i.e., energy production, conversion, and end-use technologies) with commodity flows (i.e., fuels, materials, emissions, demands) of the model. As one might imagine, this ultimately leads to a fairly complex network, with seemingly unrelated processes and commodities (say, gasoline-powered light-duty vehicles and electric-powered industrial equipment) all depending on and/or reacting to each other in some way. Such complexity is representative of the real world, as economic actors in various sectors of the economy each make decisions based on information (prices, costs, quantities, etc.) that simultaneously depend on the decisions of others. The CA-TIMES model attempts to capture these decisions, at an aggregated level, within the California energy system, and therefore the RES is built to reflect, as accurately as possible, the system as it exists today and the potential pathways it could take in the future.

Figure 20 shows an extremely simplified schematic of the CA-TIMES Reference Energy System. The diagram is helpful for illustrating the model's main components in a linear fashion; however, it fails to represent the numerous feedbacks and the complex web of interdependencies that exist within the model. For instance, progressing from left to right, one sees how the model takes primary energy resources (e.g., crude oil) and feeds them to the fuel conversion sector where the primary resources are turned into final energy commodities (e.g., gasoline, electricity) with varying degrees of efficiency, dependent on technology.[22] These final energy commodities are then consumed by technologies in the various end-use sectors, in order to produce enough useful energy to meet the required energy service demands (e.g., VMT, PMT, TMT).

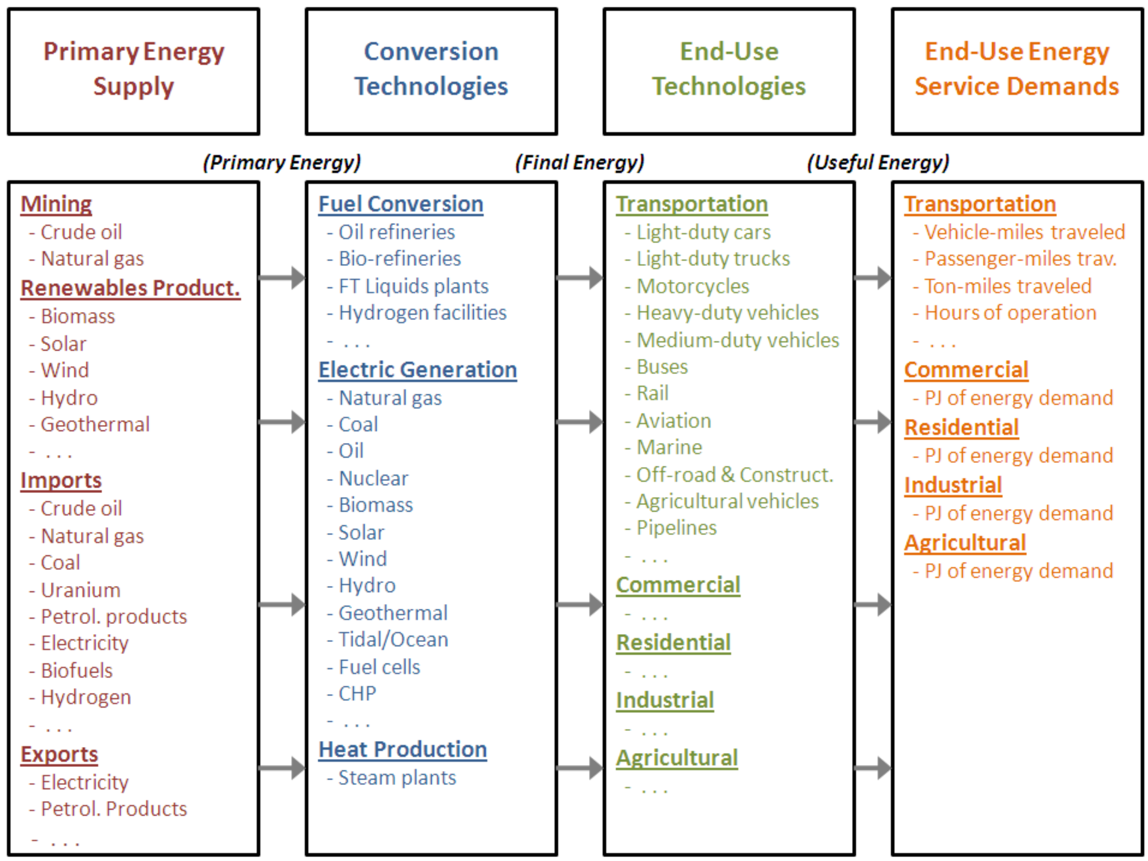



**Figure 20 Simplified Schematic of the CA-TIMES Reference Energy System**

[22] A point of clarification: Note that in the diagram imports of refined petroleum products, electricity, biofuels, and hydrogen are shown to feed the fuel conversion sector when, in reality, these final energy commodities would bypass the fuel conversion sector and go directly to the end-use technologies.

*Electric Generation Sector*

The electric generation technologies in CA-TIMES are part of the larger fuel conversion sector. These technologies consume primary (and even some secondary) energy resources and convert them to a final energy commodity, electricity. (In certain cases, heat is also produced as a by-product.) Twenty-five (25) separate power plant technologies are used to represent California's entire generation system in the base-year 2005 (Table 7). A further thirty-seven (37) are available in future years as potential technologies in which CA-TIMES can choose to invest. The model aggregates the generation capacity of similar plant types (e.g., natural gas combined-cycle), as opposed to representing every single one of California's 690+ power plants as a separate entity (EPA, 2009). This distinction is important, as it should be recognized that CA-TIMES has been designed to be an energy *systems* model, not exclusively a power market model like PROSYM or ReEDS.[23] Such fine resolution would be beyond the scope of the current analysis.

[23] For further information on PROSYM, see the Ventyx webpage: http://www.ventyx.com/analytics/market-analytics.asp. For further information on ReEDS, see the NREL webpage: http://www.nrel.gov/analysis/reeds/.

**Table 7 Electric Generation Technologies in CA-TIMES**

| Base-Year Technologies | Future Technologies |
|---|---|
| Oil Steam (Distillate, Jet Fuel, and RFO) | Natural Gas Combustion (Gas) Turbine (NGGT) |
| Diesel Oil Combustion Turbine | Advanced Natural Gas Combustion (Gas) Turbine (NGGT) |
| Diesel Oil Combined-Cycle | Natural Gas Combined-Cycle (NGCC) |
| Natural Gas Combustion (Gas) Turbine (NGGT) | Advanced Natural Gas Combined-Cycle (NGCC) |
| Natural Gas Steam Turbine (NGST) | Advanced Natural Gas Combined-Cycle (NGCC), w/CCS |
| Natural Gas Combined-Cycle (NGCC) | Coal Steam |
| NGGT, Combined Heat & Power (CHP) | Advanced Coal Int. Gasif. Combined-Cycle (IGCC) |
| Coal Steam | Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS |
| Biomass Steam (Forest Residues) | Biomass IGCC (Forest Residues) |
| Biomass Steam (Municipal Solid Waste, Mixed) | Biomass IGCC (Municipal Solid Waste, Mixed) |
| Biomass Steam (Municipal Solid Waste, Paper) | Biomass IGCC (Municipal Solid Waste, Paper) |
| Biomass Steam (Municipal Solid Waste, Wood) | Biomass IGCC (Municipal Solid Waste, Wood) |
| Biomass Steam (Municipal Solid Waste, Yard) | Biomass IGCC (Municipal Solid Waste, Yard) |
| Biomass Steam (Orchard and Vineyard Waste) | Biomass IGCC (Orchard and Vineyard Waste) |
| Biomass Steam (Pulpwood) | Biomass IGCC (Pulpwood) |
| Biomass Steam (Agr. Residues, Stovers/Straws) | Biomass IGCC (Agricultural Residues, Stovers/Straws) |
| Biomass Steam (Energy Crops) | Biomass IGCC (Energy Crops) |
| Biogas from Landfills and Animal Waste Digesters | Biogas from Landfills and Animal Waste Digesters |
| Geothermal | Geothermal, in California |
| Hydroelectric, Conventional | Geothermal, in Western U.S. Outside California |
| Hydroelectric, Reversible (Pumped Storage) | Hydroelectric, Conventional |
| Wind | Hydroelectric, Reversible (Pumped Storage) |
| Solar Thermal | Wind, Lower Class Resources in CA |
| Solar Photovoltaic | Wind, Higher Class Resources in CA |
| Nuclear, Conventional Light Water Reactors (LWR) | Wind, Lower Class Resources in Western U.S. Outside CA |
| | Wind, Higher Class Resources in Western U.S. Outside CA |
| | Wind, Offshore |
| | Solar Thermal, in CA |
| | Solar Thermal, in Western U.S. Outside CA |
| | Solar Photovoltaic |
| | Nuclear, Conventional Light Water Reactors (LWR) |
| | Nuclear, Pebble-Bed Modular Reactor (PBMR) |
| | Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR) |
| | Molten Carbonate Fuel Cell |
| | Tidal and Ocean Energy |
| | Generic Distributed Generation – Baseload |
| | Generic Distributed Generation – Peak |

In order to paint a realistic picture of the current electricity landscape in California, the CA-TIMES electric generation sector is calibrated to the base-year 2005 based on data from a variety of sources, including most notably McCarthy (2009), CARB (2010b), CEC (2010b), and the California Biomass Collaborative (CBC, 2009). The types of data needed for calibration include plant efficiencies (i.e., heat rates), fuel input shares, fixed and variable O&M costs, generation capacities, scheduled capacity retirements, and plant-specific availabilities by timeslice. The model is then calibrated to the years 2006–2010 by carefully controlling the capacity investment in, and utilization of, future technologies (from the perspective of 2005), using the same sources listed above. (Note that while data for 2010 is not yet available in full, McCarthy (2009) has estimated what California's 2010 generation mix is likely to be in a baseline scenario.) After 2010, the model is free, more or less, to invest in any of the potential future power plant technologies shown in Table 7, subject to certain constraints on capacity growth and policies, such as the state's Renewable Portfolio Standard (RPS). The types of input assumptions that are needed for the future technologies are the same as those mentioned above, as well as a few others: start years (i.e., first year of plant availability), plant lifetimes (in years), investment costs, transmission costs, technology-specific discount rates (i.e., hurdle rates), and maximum annual limits to capacity growth.

Power plant investment, utilization, and fuel use decisions in CA-TIMES are made based on the principle of cost minimization (over the entire lifetimes and lifecycles of the technologies). In this sense, one might suppose that CA-TIMES in some way approximates an electricity dispatch model. While this may be true in a basic sense, it is not an entirely accurate depiction of the current version of the model. For instance, there are forty-eight (48) timeslices[24] in CA-TIMES, a number much less than typical power market models (which have hundreds or thousands of timeslices) but considerably more

[24] In the field of energy-economic systems modeling, a "timeslice" refers to the temporal disaggregation of the model. It represents a pre-defined length of time (typically on the order of hours, weeks, months, or years), for which the modeler provides data to the model. The model then treats each individual timeslice as homogenous throughout the year when carrying out its optimization. Generally speaking, the more timeslices available to the model, the more accurate the solution. However, that being said, there are important trade-offs with respect to model computation time and data availability.

than typical MARKAL-TIMES and other energy systems models (with only 6 to 12). This finer level of resolution offers certain advantages, paramount of which is a more realistic optimization/solution/scenario.

Each model year of CA-TIMES is divided up into six “seasons”, or rather, pairs of months:

- January/February
- March/April
- May/June
- July/August
- September/October
- November/December

These month-pairs are subsequently partitioned into eight three-hour time blocks:

- 0:00 – 3:00
- 3:00 – 6:00
- 6:00 – 9:00
- 9:00 – 12:00
- 12:00 – 15:00
- 15:00 – 18:00
- 18:00 – 21:00
- 21:00 – 24:00

The combination of the six month-pairs and eight time blocks leads to the 48 timeslices of the model (6 x 8 = 48). Every timeslice is unique; but within each, the representation is homogenous. For example, the time block between 6:00 to 9:00 during the January/February season is the same on January 4 as it is on January 23, February 12, or any other day during January or February. In addition, from the model’s perspective the timeslices are not chronological: in other words, what happens in the January/February 3:00-6:00 timeslice has little bearing on what happens in the 6:00-9:00 timeslice of the same season. The model treats each timeslice distinctly when making dispatch decisions. Other considerations that are not included in CA-TIMES but that would bear on dispatch decisions in reality include power plant air pollutant emissions rules, unexpected outages, and ramp rates.

Incorporating a fairly high degree of timeslice resolution into the model is important because electricity demand and supply fluctuates over the course of the day, week, month, and year. This is illustrated by the “heat maps” of Figure 21, where red colors indicate high values, yellow/orange indicates intermediate values, and green indicates low values. Clearly, California electricity demands peak during the afternoons and evenings of summer and early-autumn days. For the most part, this coincides with solar insolation (i.e., solar power potential), which is strong in California throughout the year and which peaks in the late-morning and early-afternoon. In contrast, wind speeds (i.e., wind power potential) tend to be strongest during the nighttime hours of spring and summer days, matching poorly the times of the day/year with the highest electricity demands. (This data is for 2003, and comes from McCarthy and Yang (2008a).)

**Total Elec. Demand (share of year)**

| | | T1 0:00 => 3:00 | T2 3:00 => 6:00 | T3 6:00 => 9:00 | T4 9:00 => 12:00 | T5 12:00 => 15:00 | T6 15:00 => 18:00 | T7 18:00 => 21:00 | T8 21:00 => 24:00 |
|---|---|---|---|---|---|---|---|---|---|
| 1JF | January/February | 1.4% | 1.5% | 1.9% | 2.1% | 2.0% | 2.1% | 2.2% | 1.8% |
| 2MA | March/April | 1.5% | 1.5% | 1.9% | 2.1% | 2.1% | 2.0% | 2.2% | 1.8% |
| 3MJ | May/June | 1.6% | 1.6% | 2.0% | 2.3% | 2.4% | 2.4% | 2.3% | 2.0% |
| 4JA | July/August | 1.8% | 1.8% | 2.2% | 2.7% | 3.0% | 3.1% | 2.8% | 2.3% |
| 5SO | September/October | 1.6% | 1.7% | 2.1% | 2.4% | 2.6% | 2.7% | 2.5% | 2.0% |
| 6ND | November/December | 1.6% | 1.6% | 2.0% | 2.2% | 2.1% | 2.2% | 2.4% | 2.0% |

**Wind Speeds (m/s)**

| | | T1 | T2 | T3 | T4 | T5 | T6 | T7 | T8 |
|---|---|---|---|---|---|---|---|---|---|
| 1JF | January/February | 5.3 | 5.2 | 5.0 | 4.9 | 5.2 | 5.1 | 5.2 | 5.4 |
| 2MA | March/April | 8.9 | 8.4 | 7.4 | 6.7 | 7.3 | 8.4 | 9.3 | 9.3 |
| 3MJ | May/June | 10.5 | 9.7 | 8.5 | 7.7 | 8.2 | 9.6 | 10.7 | 10.7 |
| 4JA | July/August | 9.9 | 8.6 | 7.1 | 5.9 | 6.9 | 8.9 | 10.9 | 11.0 |
| 5SO | September/October | 6.9 | 6.3 | 5.6 | 4.9 | 5.5 | 6.1 | 6.6 | 7.2 |
| 6ND | November/December | 5.9 | 5.7 | 5.1 | 4.9 | 5.5 | 5.6 | 6.1 | 6.1 |

**Solar Insolation ($W/m^2$)**

| | | T1 | T2 | T3 | T4 | T5 | T6 | T7 | T8 |
|---|---|---|---|---|---|---|---|---|---|
| 1JF | January/February | 0.0 | 0.0 | 315.9 | 668.6 | 609.8 | 246.7 | 0.0 | 0.0 |
| 2MA | March/April | 0.0 | 23.7 | 536.8 | 723.5 | 693.5 | 422.8 | 0.0 | 0.0 |
| 3MJ | May/June | 0.0 | 118.4 | 680.0 | 791.0 | 781.3 | 583.3 | 50.0 | 0.0 |
| 4JA | July/August | 0.0 | 80.0 | 619.9 | 785.6 | 755.2 | 535.8 | 39.2 | 0.0 |
| 5SO | September/October | 0.0 | 11.2 | 549.1 | 756.5 | 714.7 | 352.3 | 0.0 | 0.0 |
| 6ND | November/December | 0.0 | 0.0 | 377.4 | 767.1 | 723.6 | 234.3 | 0.0 | 0.0 |

**Figure 21 Electricity Demand, Wind Speeds, and Solar Insolation for Each of the 48 Timeslices in CA-TIMES**

In the CA-TIMES model, the timing of electricity demands is specified for each of the end-use sectors, based on unpublished data from Ryan McCarthy that feeds into his EDGE-CA electricity dispatch model. The data represents the base-year 2005, and for the industrial, commercial, residential, and agricultural end-use sectors, the timing of electricity demands (across the 48 timeslices of the model) is assumed to follow the same temporal profile in all model years. Transportation demands for electricity are treated separately, however. In fact, in the current version of the model, these demands are only specified at the seasonal level, allowing the model to decide the optimal time to recharge plug-in electric vehicles. The only exception in the transport sector is the rail subsector, whose electricity demand profiles (for light- and heavy-rail) are currently known; hence, their demands are assumed to follow the same profile in all future years.

On the supply side the availability of all electric generation technologies are restricted to capacity factors within each timeslice that are consistent with historical averages (for thermal power plants, hydro, and nuclear) and resource availability (for wind, solar, and other renewables) for actual power plants and resources in California. These capacity factors depend on technological constraints to production (e.g., planned and unplanned outages due to maintenance), as well as on the timing of renewable resource potential (e.g., wind and hydro availability and solar insolation). In defining timeslice-specific capacity factors for the CA-TIMES model, information on power plant and renewable resource availability data is sourced from the EDGE-CA electricity dispatch model by McCarthy and Yang (2009), which compiles a large amount of data on historical outage periods for all thermal power plants in California, as well as actual wind speed and solar insolation profiles for several different sites in the state.

The CA-TIMES model also captures the cost of investing in new electrical transmission and distribution lines. This is especially important for "stranded" renewable resources that exist in remote regions of the western U.S. and Canada (e.g., solar, wind, and geothermal), for which transmission distances, and thus costs, would be rather significant if these resources were tapped for the California market. Transmission investment cost estimates for various renewable resource types are based on the California Public Utility

Commission's "33% RPS Implementation Analysis", which includes a spreadsheet model developed by the consulting firm E3 (CPUC, 2009).

*Supply Sector*

The supply sector is the largest and most complex sector of the CA-TIMES model, with respect to the sheer number of technologies and fuels that comprise it and the web of processes and commodity flows that link together to form its network. It is the most fundamental of all sectors in the model, since it is the source of all primary energy resources and is responsible for delivering all energy commodities (except for electricity) to both the fuel conversion and end-use sectors.

A number of primary energy resources are produced, or have the potential to be produced, in California or in surrounding states. CA-TIMES represents the production of these resources with supply curves of varying complexity. In the case of crude oil and natural gas, the "supply curves" are simply exogenous price projections for each future year, which are sourced from other studies (e.g., EIA (2010a) and IEA (2010)). Because oil and natural gas are globally-traded commodities and California only makes up a small share of global consumption/production, California is assumed to be a price-taker for these energy resources under the CA-TIMES framework – hence, the exogenous price projections, despite the fact that crude oil and natural gas are produced in California. In the case of biomass, CA-TIMES makes us of unique supply curves for each of twelve different feedstock types that have the potential to be produced "sustainably" (i.e., no water for irrigation, thus rain-fed, if water is needed for feedstock production) in

California and/or the Western United States outside of California. The supply curves are taken from Parker (2010), and the feedstocks include Forest Residues, Municipal Solid Waste (Mixed)[25], Municipal Solid Waste (Paper), Municipal Solid Waste (Wood), Municipal Solid Waste (Yard), Orchard and Vineyard Waste, Pulpwood, Agricultural Residues (Stovers and Straws), Energy Crops (Herbaceous), Yellow Grease, Animal Tallow, and Corn.

The CA-TIMES model also allows imports of primary energy resources and final energy commodities. For instance, because California does not have the capability to mine coal or uranium, these energy resources can be imported into the state from elsewhere in the U.S. or from abroad. And even for commodities that California can produce, the model still allows for a certain quantity to be imported from outside the state, as is the case for crude oil, natural gas (via pipeline or LNG), refined petroleum products (e.g., gasoline diesel, jet fuel, kerosene, residual fuel oil, etc.), biofuels (e.g., corn ethanol, cellulosic ethanol, sugarcane ethanol, bio-diesel, etc.), and hydrogen. Supply curves and/or exogenous price projections are specified for each of these imported commodities.

Dozens of fuel transport and delivery technologies are used in CA-TIMES to distribute the various primary and final energy commodities to the fuel conversion and end-use sectors. Along the way, production, transport, and delivery costs are assigned, and upstream emissions are allocated. The bulk of primary energy resources are delivered to the fuel conversion portion of the supply sector, which consists of crude oil refineries,

[25] Municipal Solid Waste (Mixed) includes the MSW (Dirty) and MSW (Food) categories from Nathan Parker's dissertation work.

bio-refineries, Fischer-Tropsch poly-generation plants, and hydrogen production facilities.

The refinery technology in CA-TIMES is able to flexibly produce a range of different petroleum products, taking crude oil, natural gas liquids, natural gas, and electricity as inputs (Figure 22). Crude oil and natural gas liquids are feedstock inputs (i.e., their carbon and energy content is converted into the fuel products), while the remaining energy carriers are combusted at the refinery in order to generate energy/heat for the various refining operations. In addition, a small fraction of the input crude oil is also combusted. Hydrogen is produced as an intermediary product/input at the refinery using natural gas steam methane reformation, though this process is not explicitly modeled. The outputs produced at the refinery include distillate heating oil #2, low-sulfur highway diesel (<500 ppm S), ultralow-sulfur highway diesel (<15 ppm S), conventional gasoline, reformulated gasoline, jet fuel, kerosene, high-sulfur residual fuel oil, low-sulfur residual fuel oil, liquefied petroleum gases (LPG), methanol, petrochemical feedstocks, asphalt, and petroleum coke. Reflective of a real-world refinery, the flexible technology in CA-TIMES is constrained from over-producing each fuel product by setting an upper limit on the share of total refinery output that can come from a particular fuel. These fuel product splits are relaxed slightly over time, and along with refinery efficiencies and resource inputs, they are calibrated to the base-year 2005, using data from the CEC's Energy Almanac (CEC, 2010a), the EIA Petroleum Navigator (EIA, 2010d), and the assumptions to the Petroleum Market Module of the EIA's NEMS model (EIA, 2010c). Through a process known as “capacity creep”[26], the existing stock of California refineries is allowed to expand over time. Estimates of future refinery creep for California refineries have been put at about 0.45% per year according to the CEC (CEC, 2010c). Thus, the state’s refining capacity is able to grow, albeit with a much smaller capital outlay than would be expected if a “greenfield” refinery were to be built on a new site. Such greenfield expansions are also possible in the model through investments in a future refinery technology.

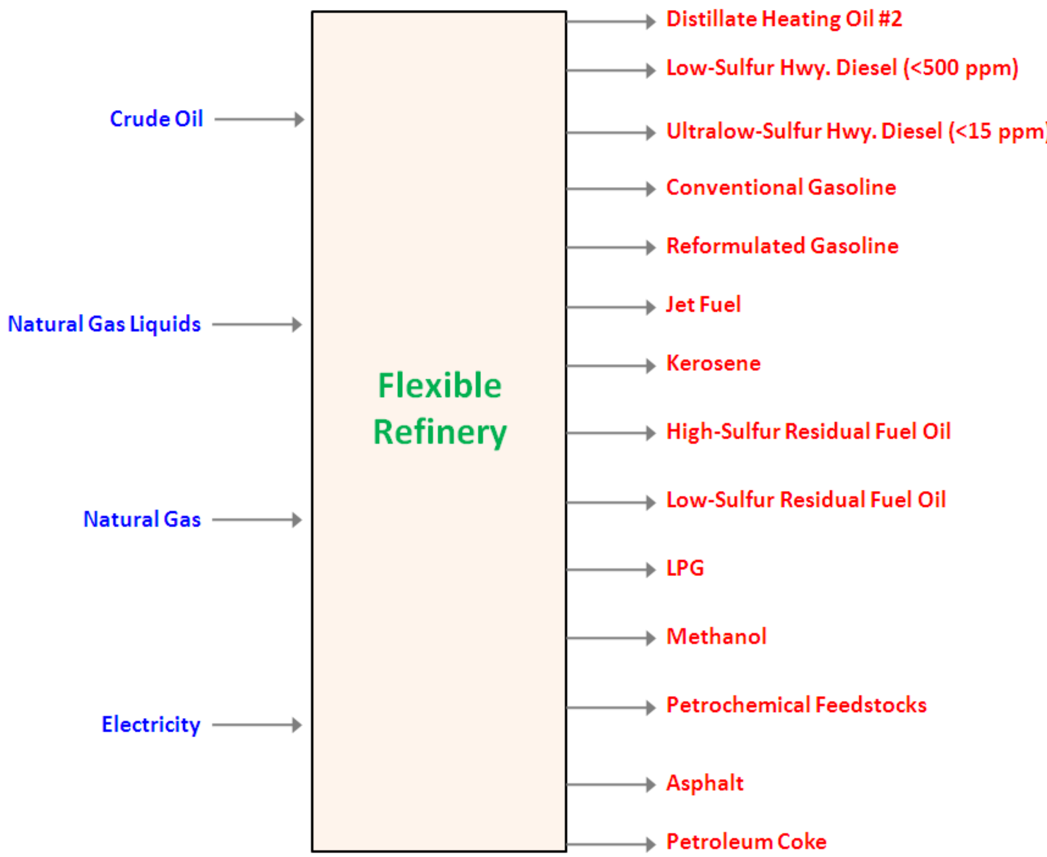



**Figure 22 Simplified Schematic of Flexible Refinery Technology in CA-TIMES**

[26] Refinery capacity creep is the term used to describe the cumulative result of many small projects and productivity enhancements that enable a refinery to increase crude oil input over time.

Several different types of bio-refinery technologies are modeled in CA-TIMES (Table 8), though only a couple of these are available in the base-year 2005: bio-diesel production facilities consuming yellow grease or animal tallow as feedstocks. Ethanol supply until 2010 is met by imports of corn ethanol from the Midwestern U.S. and sugarcane ethanol from Brazil. Soon after 2010, the model is able to invest in cellulosic ethanol plants (via either the biochemical or thermochemical pathway) and bio-derived residual fuel oil plants (via a pyrolysis bio-oil pathway). These future technologies consume one of nine types of cellulosic feedstock. In addition to producing their liquid fuel products, these bio-refineries also generate a small amount of electricity as a by-product. Feeding this low-carbon electricity to the grid can displace more carbon-intensive sources of electricity, such as natural gas plants. All future bio-refinery technologies are characterized by biomass input efficiencies, investment costs, fixed and variable O&M costs, annual capacity factors, technology-specific hurdle rates, year-to-year limits on capacity growth, and a variety of other information. These technology characterizations largely come from Bain (2007).

**Table 8 Bio-Refineries and FT Poly-Generation Plants in CA-TIMES**

| Production Technology | Feedstock Types |
|---|---|
| **Cellulosic Ethanol Plants** | |
| Biochemical Pathway (50 or 100 million gal per year)<br>Thermochemical Pathway (50 or 100 MGY) | Forest Residues<br>Municipal Solid Waste, Paper<br>Municipal Solid Waste, Wood<br>Municipal Solid Waste, Yard<br>Orchard and Vineyard Waste<br>Pulpwood<br>Agricultural Residues, Stovers/Straws<br>Energy Crops |
| **Bio-Residual Fuel Oil Plants** | |
| Pyrolysis Bio-Oil Pathway (25 or 100 MGY) | Forest Residues<br>Municipal Solid Waste, Mixed<br>Municipal Solid Waste, Paper<br>Municipal Solid Waste, Wood<br>Municipal Solid Waste, Yard<br>Orchard and Vineyard Waste<br>Pulpwood<br>Agricultural Residues, Stovers/Straws<br>Energy Crops |
| **Renewable Bio-Diesel Plants** | |
| Hydro-treatment Pathway (50 or 100 MGY) | Yellow Grease<br>Animal Tallow |
| **Fischer-Tropsch Poly-Generation Plants** | |
| Biomass Gasification (61 MGY)<br>Biomass Gasification, w/ CCS (61 MGY) | Forest Residues<br>Municipal Solid Waste, Mixed<br>Municipal Solid Waste, Paper<br>Municipal Solid Waste, Wood<br>Municipal Solid Waste, Yard<br>Orchard and Vineyard Waste<br>Pulpwood<br>Agricultural Residues, Stovers/Straws<br>Energy Crops |
| Coal-Biomass Gasification, Syngas RC, w/ CCS (138 MGY)<br>Coal-Biomass Gasification, Syngas OT, w/ CCS (112 MGY)<br>Coal-Biomass Gasification, Syngas OT, w/ CCS (506 MGY) | Coal<br>Forest Residues<br>Municipal Solid Waste, Mixed<br>Municipal Solid Waste, Paper<br>Municipal Solid Waste, Wood<br>Municipal Solid Waste, Yard<br>Orchard and Vineyard Waste<br>Pulpwood<br>Agricultural Residues, Stovers/Straws<br>Energy Crops |

Fischer-Tropsch (FT) coal-biomass poly-generation plants represent yet another category of potential future fuel conversion technologies in CA-TIMES (Table 8). These plants consume one of nine types of cellulosic feedstock and then produce some combination of synthetic gasoline, diesel, jet fuel, and/or electricity. Co-firing with coal is an option with certain plant designs. In the current version of CA-TIMES, I have chosen to include five out of the sixteen biomass-to-liquid (BTL) and coal/biomass-to-liquid (CBTL) process configurations developed and analyzed by Kreutz et al. (2008). Using their naming convention, the following plant types are characterized in CA-TIMES: BTL-RC-V, BTL-RC-CCS, CBTL-RC-CCS, CBTL-OT-CCS, CBTL2-OT-CCS. According to the authors, all of these system designs are based on commercial or near-commercial technologies. The main differences between them have to do with their varying sizes, biomass-to-coal input ratios, and fuel/electricity product splits; whether or not CCS is utilized or $CO_2$ is vented to the atmosphere; and whether a once through (OT) or recycle (RC) approach is used for the initially unconverted synthetic gas ("syngas"). (Note that RC systems maximize FT liquids production, while OT systems allow for more electricity generation at the expense of reduced FT liquids production.) Two of the five plants made available to CA-TIMES consume only biomass (i.e., no coal co-firing); thus, they produce liquid fuel products with zero or significantly negative carbon intensities. For example, the BTL-RC-CCS plant design is an example of a negative emissions technology, since it takes carbon from biomass (which originally pulled $CO_2$ out of the atmosphere via photosynthesis) and permanently stores it underground. Further, because the three CBTL plants with coal-biomass co-firing each utilize CCS, they also produce liquid fuel products with relatively attractive carbon intensities, even though coal is used an input fuel. These carbon intensities are significantly better, or at least no worse, than petroleum-based gasoline. From a technological perspective, carbon capture and storage is particularly attractive with these FT liquids poly-generation plants because the $CO_2$ stream that is generated is naturally concentrated – in other words, a nearly pure stream of $CO_2$ is generated, by default, as a by-product of the FT process, thus the added costs of $CO_2$ capture are quite low. All future FT BTL/CBTL poly-generation plant technologies in CA-TIMES are characterized by coal and biomass input efficiencies, investment costs, fixed and variable O&M costs, annual capacity factors, technology-specific hurdle rates, year-to-year limits on capacity growth, and a variety of other information. The technology and cost assumptions come from Kreutz et al. (2008).

Hydrogen is supplied to the various end-use sectors in CA-TIMES via a number of different pathways. The following hydrogen production technologies are available to the model in future years: Coal Gasification (w/ and w/o CCS), Natural Gas Steam Methane Reformation (w/ and w/o CCS), Water Electrolysis, and Biomass Gasification (w/ and w/o CCS). Both coal gasification facilities in the model are intended for centralized production; the large-scale facility produces 1,200 metric tonnes of $H_2$ per day (t/d), while the mid-size facility produces 24 t/d.[27] The same situation is true of natural gas SMR facilities, except that a small-scale technology (0.48 t/d) is also available for distributed production at a refueling station. A mid-size water electrolysis technology (24 t/d) is available for centralized production, as well as a small-scale technology (0.48 t/d) for distributed production. All mid-size biomass gasification facilities (24 t/d), which consume one of the nine types of cellulosic feedstock, are intended for centralized production, and the biomass technologies that utilize CCS are potential negative emissions technologies. Hydrogen is the only commodity produced at each of the

[27] A 1,200 tonne/day H2 production facility is roughly equivalent to producing 438 million gasoline gallon equivalents (gge) per year on an energy basis. A 24 t/d facility is equivalent to 8.76 million gge/yr, while a 0.48 t/d facility is equivalent to 0.175 million gge/yr. A 2.74 t/d refueling station is equivalent to 1.00 million gge/yr.

production facilities, no matter the technology: no electricity co-generation takes place. All future hydrogen production technologies in CA-TIMES are characterized by coal, natural gas, biomass, electricity, and/or water input efficiencies, investment costs, fixed and variable O&M costs, annual capacity factors, technology-specific hurdle rates, year-to-year limits on capacity growth, and a variety of other information. The technology and cost assumptions draw heavily from the U.S. EPA's 9-region MARKAL model (EPA, 2008a), which is partially based on NRC (2004).

After it is produced, hydrogen is distributed to end-use sector technologies by either pipeline or truck transmission and delivery technologies, depending on the form in which the hydrogen is to be consumed, gas or liquid (Figure 23). (Of course, hydrogen produced with distributed technologies requires no transmission and delivery since the production occurs at the refueling station.) In the model, distinctions are made between three different levels of geographical aggregation: Urbanized Area (UA), Urban Cluster (UC), and Rural Region (RR). This has a bearing on the costs of hydrogen transmission and distribution. An urbanized area generally refers to a densely settled area of 50,000 or more people; an urban cluster refers to an area of at least 2,500 people but fewer than 50,000 people; and a rural region is any area that falls outside of the two urban designations. Pipeline delivery of gaseous hydrogen from a centralized production facility first occurs via long-distance transmission to a UA, UC, or RR city-gate. Then, trunk delivery via pipeline takes place within the UAs and UCs. Finally, service pipelines distribute hydrogen to refueling stations. (Note that in rural regions, the trunk delivery step is bypassed.) Truck delivery of liquid hydrogen is done in much the same way. First, long-distance transmission to UA, UCs, and RRs is carried out by large trucks; then, for UAs and UCs small trucks distribute hydrogen to refueling stations. An alternate pathway for UAs and UCs is for gaseous hydrogen to be transported to the city-gate by means of a pipeline; then, the hydrogen is liquefied and loaded onto a truck for distribution to the refueling station. Once at the refueling station, which is assumed to have a dispensing capacity of 2,740 kg/day, the model can choose to fuel hydrogen vehicles with either gaseous or liquefied hydrogen. This choice depends on the full lifecycle costs of the hydrogen fuel (production + delivery), as well as the investment costs of the hydrogen vehicles. Each step in the delivery process has some cost, efficiency, and emission flow associated with it. These technology characterizations are based on the EPAUS9r MARKAL model (EPA, 2008a), NRC (2004), and the U.S. DOE's Hydrogen Analysis (H2A) model (DOE, 2008).

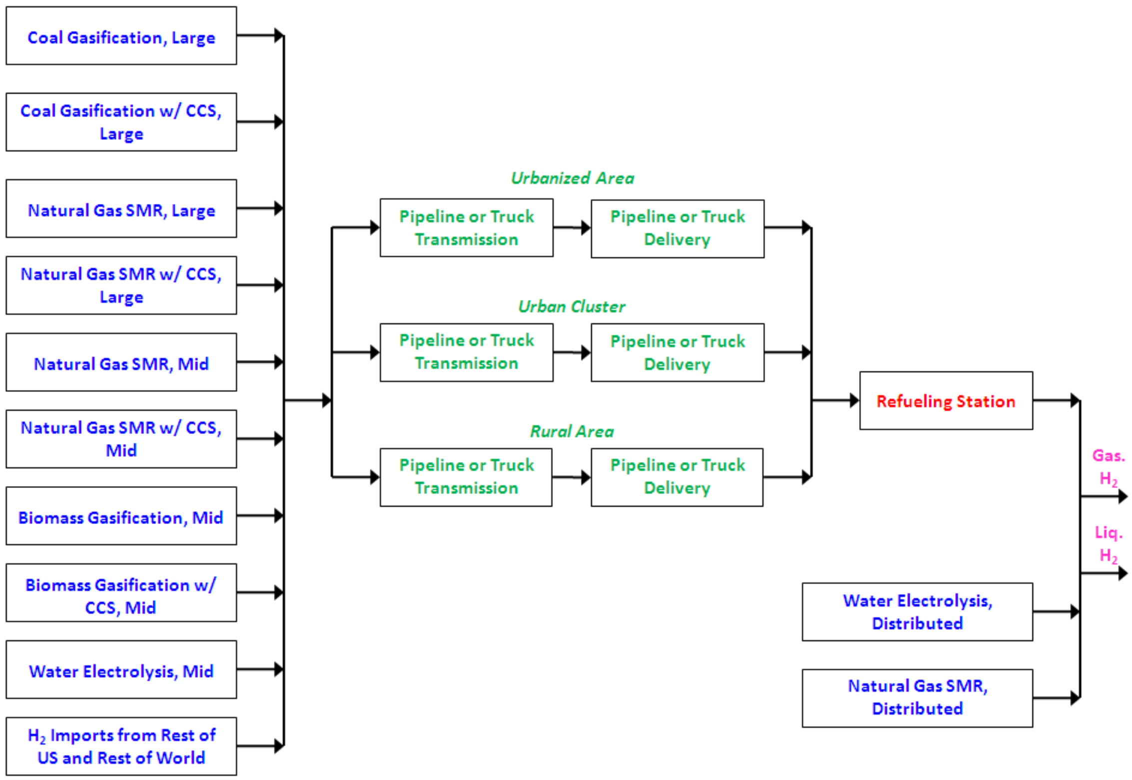



**Figure 23 Simplified Schematic of Hydrogen Production and Supply Technologies in CA-TIMES**

At this point, it should be noted, however, that despite the somewhat sophisticated treatment of hydrogen transmission and delivery in CA-TIMES that has been described in the above paragraphs, in the current version of the model, there are no constraints to specify demand splits between urbanized areas, urban clusters, and rural regions. In other words, there are no constraints to ensure a transition from distributed hydrogen production in the early years to centralized production later on, or from the large metropolitan areas of the state ("lighthouse cities") in the early stages to rural regions and smaller towns several years thereafter. The current version of CA-TIMES does not make these fine geographic distinctions since it treats California as a single region, although a more sophisticated spatial representation could certainly be added at a later date, as has already been discussed by other members of our research team. Such geographic detail is outside the scope of the present analysis. However, one of the goals of my dissertation work to this point has been to put in place most of the model structure needed for analyzing these issues, with a realization that there is considerable interest within ITS-Davis in analyzing spatial aspects of hydrogen (as well as biofuels) infrastructure development. I leave these interesting questions to others and to future research.

*Transportation Sector*

The transportation sector of CA-TIMES is the most detailed and disaggregated of the five end-use demand sectors. Indeed, the level of bottom-up technological detail is arguably greater than typical energy systems models, especially for the non-LDV transport subsectors. As shown in Table 9, the transport sector consists of eleven separate subsectors; a few of these subsectors are further disaggregated into segments (e.g., Transit Buses, School Buses, etc.). Each segment represents a unique service demand, which the model must satisfy. (The units of each service demand are shown in parentheses.) For instance, demand for light-duty cars is distinct from light-duty trucks. Both of these are exogenously specified by the modeler, and there is no possibility for endogenous segment-switching (i.e., from LDTs to LDCs) – at least in the current version of the model – unless the modeler decides to run a scenario with different demands for each segment. In general, demand projections are based on government forecasts and/or other research studies.

Within each subsector, a number of technologies exist for satisfying the specified end-use demands in each subsector/segment (Table 9). In the base-year 2005, and up through

2010, the model is calibrated to historical data. This effectively means that, aside from some Flex-Fuel E-85 vehicles in the light-duty subsector, the model is constrained to invest only in fossil fuel technologies between 2005 and 2010. (Note that in Table 9, a '*' represents technologies that were used in the base-year 2005.) After 2010, the model is free to invest in any technology, depending on its assumed first year of availability and subject to constraints on its growth. From a modeling perspective, every transport sector technology is represented in essentially the same way. The technologies consume fuel and energy carriers (gasoline, diesel, jet fuel, RFO, natural gas, biofuels, hydrogen, electricity, etc.) and produce end-use service demands. (These fuels/carriers come from the supply sector, as described previously.) Each technology has an assumed efficiency for turning energy into service demand, and each is given a fixed upper bound on its annual availability (e.g., the maximum number of miles that a single light-duty car can travel within a given year). For the base-year 2005, efficiencies and availabilities are calculated for each base-year technology in each transport subsector and segment. It is also necessary to specify average vehicle lifetimes and the stock of technologies in the base-year (i.e., how many vehicles of each type were available in each subsector and segment in 2005). Future technologies require much the same information, and in addition the technology's first year of market availability, investment and O&M costs (aside from fuel costs), and technology-specific hurdle rates. In some of these cases (e.g., for efficiencies and investment costs), the input assumptions are exogenously specified trajectories for all future model years. Other studies are used to inform these assumptions. With all of this information at its disposal, the model is free to make fuel use and investment decisions by trading off the costs of competing end-use technologies.

Of course, certain other considerations also come into play, such as vehicle efficiency standards and renewable fuel mandates. An expanded discussion of the CA-TIMES transportation sector is found in Section II.2.3 below. Unfortunately, due to the inherent space limitations of this chapter, it is not possible to discuss the composition of each of the various transport subsectors in great detail, for example, the relative importance of freight versus passenger aviation (comparing intrastate, interstate, and international travel) or the breakdown between the various types of rail. That being said, a fair amount of research has previously been conducted on this topic for California, and the interested reader is encouraged to read through Yang, McCollum, McCarthy, and Leighty (2008) for a considerable amount of further information.

**Table 9 Transportation Sector Technologies in CA-TIMES**

| Transport Subsectors and Service Demands | Technologies† |
|---|---|
| **Light-Duty Vehicles** | |
| Light-Duty Cars (vehicle-miles traveled)<br>Light-Duty Trucks (vehicle-miles traveled) | Gasoline ICE *<br>Gasoline HEV *<br>Gasoline ICE (Moderate Eff.)<br>Gasoline ICE (Advanced Eff.)<br>Diesel ICE *<br>Diesel HEV<br>E-85 Flex Fuel ICE<br>E-85 Flex Fuel ICE (Moderate Eff.)<br>E-85 Flex Fuel ICE (Advanced Eff.)<br>E-85 Flex Fuel HEV<br>Dedicated Ethanol ICE<br>Natural Gas ICE<br>Natural Gas Bi-Fuel ICE<br>LPG ICE<br>LPG Bi-Fuel ICE<br>Gasoline PHEV 10/30/40/60<br>E-85 Flex Fuel PHEV 10/30/40/60<br>Diesel PHEV 10/30/40/60<br>Battery-Electric<br>Hydrogen Fuel Cell<br>Methanol Fuel Cell<br>Gasoline Fuel Cell |
| **Motorcycles** | |
| Motorcycles (vehicle-miles traveled) | Gasoline ICE *<br>Dedicated Ethanol ICE |
| **Heavy-Duty Trucks** | |
| Heavy-Duty Trucks (vehicle-miles traveled) | Gasoline ICE *<br>Diesel ICE *<br>Diesel ICE (+10% Eff.)<br>Diesel ICE (+20% Eff.)<br>Diesel ICE (+40% Eff.)<br>Natural Gas (CNG) ICE<br>LPG ICE<br>Dedicated Ethanol ICE<br>Dedicated Methanol ICE |
| **Medium-Duty Trucks** | |
| Medium-Duty Trucks (vehicle-miles traveled) | Gasoline ICE *<br>Gasoline HEV<br>Diesel ICE *<br>Diesel HEV<br>Natural Gas (CNG) ICE<br>Natural Gas (CNG) HEV<br>LPG ICE<br>Dedicated Ethanol ICE<br>Gasoline PHEV30<br>Diesel PHEV30<br>Natural Gas (CNG) PHEV30<br>Hydrogen ICE–HEV<br>Hydrogen Fuel Cell |
| **Buses** | |
| Transit Buses (vehicle-miles traveled)<br>School Buses (vehicle-miles traveled)<br>Intercity and Other Buses (vehicle-miles traveled) | Gasoline ICE *<br>Gasoline ICE (+20% Eff.)<br>Gasoline ICE (+40% Eff.)<br>Diesel ICE *<br>Diesel ICE (+20% Eff.)<br>Diesel ICE (+40% Eff.)<br>Diesel HEV |

| | |
|---|---|
| | Natural Gas (CNG) ICE *<br>Natural Gas (CNG) HEV<br>LPG ICE<br>Dedicated Ethanol ICE<br>Dedicated Methanol ICE<br>Gasoline PHEV30<br>Diesel PHEV30<br>Natural Gas (CNG) PHEV30<br>Electric *<br>Hydrogen ICE–HEV<br>Hydrogen Fuel Cell |
| **Rail** | |
| Commuter Rail (passenger-miles traveled)<br>Heavy Rail (passenger-miles traveled)<br>Light Rail (passenger-miles traveled)<br>Intercity Passenger Rail (passenger-miles traveled)<br>Freight Rail (ton-miles traveled) | Diesel *<br>Electric * |
| **Marine** | |
| Domestic - Intrastate/California - Large Shipping Vessel (ton-miles traveled)<br>Domestic - Intrastate/California - Harbor Craft (hours of operation)<br>Domestic - Intrastate/California - Personal Recreational Boat (hours of operation)<br>Domestic - Interstate - Large Shipping Vessel (ton-miles traveled)<br>Foreign/International - Large Marine Vessel (vessel-miles traveled) | Gasoline ICE *<br>Diesel ICE *<br>Residual Fuel Oil ICE *<br>Dedicated Ethanol ICE<br>Diesel Molten Carbonate Fuel Cell |
| **Aviation** | |
| Domestic - Intrastate/California - Passenger Aviation (passenger-miles traveled)<br>Domestic - Intrastate/California - Freight Aviation (ton-miles traveled)<br>Domestic - Intrastate/California - General Aviation (hours of operation)<br>Domestic - Interstate - Passenger Aviation (passenger-miles traveled)<br>Domestic - Intrastate/California - Freight Aviation (ton-miles traveled)<br>Foreign/International - Passenger Aviation (passenger-miles traveled)<br>Foreign/International - Freight Aviation (ton-miles traveled)<br>Other Miscellaneous Aviation (PJ of activity) | Jet Fuel Turbofan Jet Engine *<br>Aviation Gasoline Propeller *<br>Gasoline *<br>Hydrogen Turbofan Jet Engine |
| **Off-Road & Construction** | |
| Off-Road & Construction Devices (hours of operation) | Gasoline *<br>Diesel *<br>LPG/CNG *<br>Dedicated Ethanol<br>Hydrogen<br>Electricity |
| **Agriculture** | |
| Agricultural Vehicles (hours of operation) | Gasoline *<br>Diesel *<br>Dedicated Ethanol<br>Hydrogen<br>Electricity |
| **Pipelines** | |
| Natural Gas Consumption for Pipelines (PJ of NG) | Natural Gas * |

† *Notes: The '*' symbol is used to denote technologies that were used in the base-year 2005.*

*Industrial, Commercial, Residential, and Agricultural Sectors*

Because this dissertation research focuses on the transportation, electricity, and supply sectors (since they account for 85% of all GHG emissions related to fuel combustion in California), the current version of the CA-TIMES model has a fairly simple representation of end-use energy consumption in the industrial, commercial, residential, and agricultural (collectively "ICRA") sectors. Eventually, in later versions of the model and through contributions from other members of our research team, these other sectors will be modeled at a level of technological detail that is similar to that which currently exists for transportation, electricity, and supply (i.e., describing energy service demands for the different segments of each of these sectors and the technologies and fuels that can potentially be used to supply the end-use demands, such as light bulbs, air conditioner, refrigerators, etc.). In the meantime, however, in order to satisfactorily develop future energy scenarios where deep reductions in economy-wide greenhouse gas emissions are to be made, there must be at least some representation of the ICRA sectors (and the fuel they consume and emissions they generate), no matter how limited the detail. One cannot simply ignore these sectors entirely. My approach to solving this problem has been to represent final energy consumption in each of the four ICRA sectors with generic input-output technologies. Each sector possesses only one of these technologies, and each technology consumes exogenously specified quantities of various types of fuel in each year. In other words, both the supply of final energy and the demand for total useful energy are specified in energy units (e.g., PJ). The efficiency of each of the generic input-output technologies is set at 100%.

Total useful energy demand by sector and the breakdown of final energy by fuel type by sector are calibrated to published energy statistics for the base-year 2005, using the fuel use estimates of the CARB GHG Inventory (CARB, 2010b). For future years, demand trajectories and the fuel use mix are exogenously specified by the modeler; these input assumptions can be easily and quickly modified across different model runs (e.g., when running a reference case vs. a deep GHG reduction scenario). Obviously, given this rigid framework, the model is not free to make fuel use and investment decisions by trading off the costs of competing end-use technologies (e.g., boilers, furnaces, compact fluorescent light bulbs, solar hot water heating, etc.), as it is able to do in the transportation, electricity, and supply sectors. However, that being said, the framework does partially allow for feedback and interplay with the other sectors, since the fuel demands in the ICRA sectors send a price/quantity signal to these other sectors, which impacts the fuel use and investment decisions therein.

In my dissertation work, I have relied on other studies to develop future fuel use and demand scenarios for the ICRA sectors. For instance, in developing my Reference Case I draw heavily from the California Energy Commission and UC-Davis Advanced Energy Pathways (AEP) project (McCarthy et al., 2008a, b), while for my Deep GHG Reduction Scenario I base my projections on the well-known BLUE Map scenarios of the IEA's Energy Technology Perspectives (ETP) 2010 study (IEA, 2010). The projections by fuel type for these two sets of scenarios are shown for the four ICRA sectors starting from Figure 30 and Figure 60, respectively.

Figure 24 illustrates the modeling framework adopted for the industrial, commercial, residential, and agricultural end-use sectors. In each of the sectors, one or more of thirty different fuels is consumed by the generic input-output technology, and the combined intake of these fuels results in the total useful energy demand for the sector (IND/COM/RSD/AGR). Of course, not every fuel is consumed in each sector. For example, in the base-year 2005, only five different fuels were consumed in the agricultural sector, whereas more than a dozen fuels were consumed in the industrial sector.

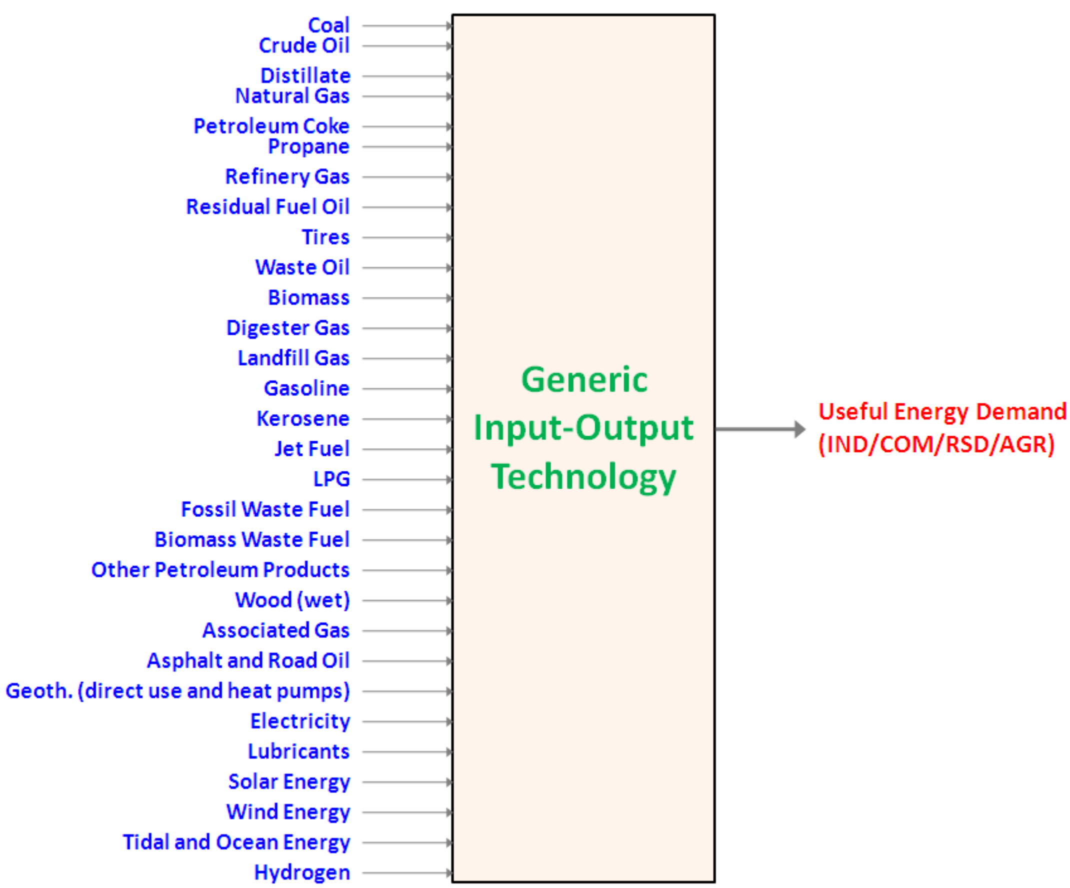



**Figure 24 Simplified Schematic of Generic Input-Output Technology Used in the Industrial, Commercial, Residential, and Agricultural Sectors**

### *II.2.3 Key Input Assumptions and Data Sources*

The results generated using the CA-TIMES model are, like any other model, entirely a function of the data and assumptions that go into building them. It is, therefore, important to review some of the key input assumptions and data sources of the model, at least those that have not already been described. That being said, because CA-TIMES is such a large model (and will only grow larger in the future), it is rather infeasible to list all assumptions in this single chapter of my dissertation, or even in an appendix. (The best sources of documentation are the underlying VEDA-TIMES spreadsheets themselves.) For this reason, I concentrate here on only certain parts of the electricity, supply, and transportation sectors, given that these are of greatest relevance and interest for the purposes of my dissertation.

*Electric Generation Sector*

As mentioned previously, calibration of the electric generation sector between 2005 and 2010 is achieved by using input to and output from the EDGE-CA electricity dispatch model for California by McCarthy and Yang (2009), which is itself largely based on the U.S. EPA's eGRID power plant database (EPA, 2009). Then, in deciding how to supply electricity after 2010, the model is able to choose amongst a suite of more than three dozen power plant technologies. In this regard, two of the most important decision-making criteria are investment costs and plant efficiencies. The next two tables summarize the Reference Case cost and efficiency assumptions of the CA-TIMES model in the particular model years, for which data is provided to CA-TIMES; the model then interpolates for the costs in the in-between years.[28] In general, investment cost and efficiency assumptions are taken from the EIA's AEO2010 Reference Case. (Fixed and variable O&M costs are also generally taken from the same source, although they are not shown here.) Some notable exceptions include tidal/ocean energy plants, for which costs come from the IEA's ETP2008 report (IEA, 2008), and nuclear plants, for which costs and efficiencies are calculated based on a combination of data from several sources (Ansolabehere, 2003; DOE, 2001; EIA, 1998, 2010a; NEI, 2003; OECD, 2002). Note that the efficiencies of the three nuclear plants are not expressed in percentages, but rather in terms of metric tonnes of enriched uranium input per petajoule of produced electricity. The latter can be calculated with knowledge of both the burn-up (i.e., fuel utilization)[29] rate and thermal efficiency of each nuclear plant. Furthermore, the efficiency assumptions shown in the tables for non-geothermal and non-biomass renewables (e.g., solar, wind, hydro, and tidal) are simply those of an average fossil-thermal power plant. This is done so that, from a primary energy resource perspective, all power plant inputs can be represented in terms of fossil energy-equivalents. The investment cost numbers shown in the table below do not include the added costs of new transmission and distribution lines.

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[28] Note that all costs in the CA-TIMES model are expressed in 2007 U.S. dollars.

[29] The burn-up rate is defined as amount of energy output (usually in terms of kWh or MW-days) divided by the unit mass of fuel input (usually expressed in terms of heavy metal, e.g., kg Uranium).

**Table 10 Investment Cost Assumptions for New Power Plants in the Reference Case**

| Investment Costs for New Power Plants ($/kW)<br>*(Notes: Costs are interpolated between the data years shown.)* | | | | |
|---|---|---|---|---|
| | 2005 | 2015 | 2035 | 2050 |
| Natural Gas Combustion (Gas) Turbine (NGGT) | 685 | 745 | 518 | 518 |
| Advanced Natural Gas Combustion (Gas) Turbine (NGGT) | 648 | 699 | 552 | 552 |
| Natural Gas Combined-Cycle (NGCC) | 984 | 1,070 | 744 | 744 |
| Advanced Natural Gas Combined-Cycle (NGCC) | 968 | 1,048 | 698 | 698 |
| Advanced Natural Gas Combined-Cycle (NGCC), w/CCS | 1,932 | 2,054 | 1,191 | 1,191 |
| Coal Steam | 2,223 | 2,418 | 1,681 | 1,681 |
| Advanced Coal Int. Gasif. Combined-Cycle (IGCC) | 2,569 | 2,769 | 1,829 | 1,829 |
| Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS | 3,776 | 4,022 | 2,410 | 2,410 |
| Biomass IGCC (Forest Residues) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biomass IGCC (Municipal Solid Waste, Mixed) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biomass IGCC (Municipal Solid Waste, Paper) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biomass IGCC (Municipal Solid Waste, Wood) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biomass IGCC (Municipal Solid Waste, Yard) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biomass IGCC (Orchard and Vineyard Waste) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biomass IGCC (Pulpwood) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biomass IGCC (Agricultural Residues, Stovers/Straws) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biomass IGCC (Energy Crops) | 7,698 | 8,330 | 5,548 | 5,548 |
| Biogas from Landfills and Animal Waste Digesters | 5,199 | 5,625 | 3,747 | 3,747 |
| Geothermal, in California | 3,498 | 3,785 | 2,521 | 2,521 |
| Geothermal, in Western U.S. Outside California | 3,498 | 3,785 | 2,521 | 2,521 |
| Hydroelectric, Conventional | 4,583 | 4,959 | 3,303 | 3,303 |
| Hydroelectric, Reversible (Pumped Storage) | 2,291 | 2,480 | 1,652 | 1,652 |
| Wind, Lower Class Resources in CA | 3,931 | 4,254 | 2,833 | 2,833 |
| Wind, Higher Class Resources in CA | 3,931 | 4,254 | 2,833 | 2,833 |
| Wind, Lower Class Resources in Western U.S. Outside CA | 3,931 | 4,254 | 2,833 | 2,833 |
| Wind, Higher Class Resources in Western U.S. Outside CA | 3,931 | 4,254 | 2,833 | 2,833 |
| Wind, Offshore | 7,874 | 8,520 | 5,675 | 5,675 |
| Solar Thermal, in CA | 8,725 | 9,441 | 7,398 | 7,398 |
| Solar Thermal, in Western U.S. Outside CA | 8,725 | 9,441 | 7,398 | 7,398 |
| Solar Photovoltaic | 10,491 | 11,352 | 8,895 | 8,895 |
| Molten Carbonate Fuel Cell | 9,313 | 10,078 | 7,896 | 7,896 |
| Tidal and Ocean Energy | 14,667 | 12,633 | 8,567 | 6,667 |
| Generic Distributed Generation – Baseload | 1,400 | 1,515 | 1,009 | 1,009 |
| Generic Distributed Generation – Peak | 1,681 | 1,819 | 1,212 | 1,212 |
| Nuclear, Conventional Light Water Reactors (LWR) | 3,820 | 4,089 | 2,496 | 2,496 |
| Nuclear, Pebble-Bed Modular Reactor (PBMR) | 3,316 | 3,549 | 2,167 | 2,167 |
| Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR) | 2,977 | 3,186 | 1,945 | 1,945 |

**Table 11 Efficiency Assumptions for New Power Plants in the Reference Case**

| New Power Plant Efficiencies (%) *(Notes: For non-geothermal and non-biomass renewables, efficiencies are assumed to be similar to an average fossil-thermal plant. Efficiences are interpolated between the data years shown.)* | 2005 | 2035 | 2055 |
|---|---|---|---|
| Natural Gas Combustion (Gas) Turbine (NGGT) | 31.6% | 32.7% | 32.7% |
| Advanced Natural Gas Combustion (Gas) Turbine (NGGT) | 36.7% | 39.9% | 39.9% |
| Natural Gas Combined-Cycle (NGCC) | 47.4% | 50.2% | 50.2% |
| Advanced Natural Gas Combined-Cycle (NGCC) | 50.5% | 53.9% | 53.9% |
| Advanced Natural Gas Combined-Cycle (NGCC), w/CCS | 39.6% | 45.5% | 45.5% |
| Coal Steam | 37.1% | 39.0% | 39.0% |
| Advanced Coal Int. Gasif. Combined-Cycle (IGCC) | 38.9% | 45.8% | 45.8% |
| Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS | 31.6% | 41.1% | 41.1% |
| Biomass IGCC (Forest Residues) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Municipal Solid Waste, Mixed) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Municipal Solid Waste, Paper) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Municipal Solid Waste, Wood) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Municipal Solid Waste, Yard) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Orchard and Vineyard Waste) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Pulpwood) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Agricultural Residues, Stovers/Straws) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Energy Crops) | 36.1% | 43.9% | 43.9% |
| Biogas from Landfills and Animal Waste Digesters | 25.0% | 25.0% | 25.0% |
| Geothermal, in California | 10.3% | 11.3% | 11.3% |
| Geothermal, in Western U.S. Outside California | 10.3% | 11.3% | 11.3% |
| Hydroelectric, Conventional | 34.5% | 34.5% | 34.5% |
| Hydroelectric, Reversible (Pumped Storage) | 77.5% | 77.5% | 77.5% |
| Wind, Lower Class Resources in CA | 34.5% | 34.5% | 34.5% |
| Wind, Higher Class Resources in CA | 34.5% | 34.5% | 34.5% |
| Wind, Lower Class Resources in Western U.S. Outside CA | 34.5% | 34.5% | 34.5% |
| Wind, Higher Class Resources in Western U.S. Outside CA | 34.5% | 34.5% | 34.5% |
| Wind, Offshore | 34.5% | 34.5% | 34.5% |
| Solar Thermal, in CA | 34.5% | 34.5% | 34.5% |
| Solar Thermal, in Western U.S. Outside CA | 34.5% | 34.5% | 34.5% |
| Solar Photovoltaic | 34.5% | 34.5% | 34.5% |
| Molten Carbonate Fuel Cell | 43.0% | 49.0% | 49.0% |
| Tidal and Ocean Energy | 34.5% | 34.5% | 34.5% |
| Generic Distributed Generation – Baseload | 37.7% | 38.3% | 38.3% |
| Generic Distributed Generation – Peak | 33.9% | 34.5% | 34.5% |

| New Nuclear Plant Efficiencies (tonnes enriched uranium per PJ electricity) *(Notes: Efficiences are interpolated between the data years shown.)* | 2005 | 2035 | 2055 |
|---|---|---|---|
| Nuclear, Conventional Light Water Reactors (LWR) | 0.65 | 0.65 | 0.65 |
| Nuclear, Pebble-Bed Modular Reactor (PBMR) | 0.36 | 0.36 | 0.36 |
| Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR) | 0.22 | 0.22 | 0.22 |

*Supply Sector*

Supply curves for crude oil, natural gas, and coal are modeled in CA-TIMES as exogenously specified price projections, since California is assumed to be a price-taker for these energy resources under the CA-TIMES framework. In the Reference Case scenario, these trajectories, which are shown in Figure 25, come from the EIA's AEO2010 Reference Case projections (and extended post-2035 using projections from the IEA's ETP 2010 Baseline Scenario), as discussed in Section II.2.2. Interestingly, after having fallen steadily for several years, EIA forecasts oil and natural gas prices to rise significantly over the next two to three decades.

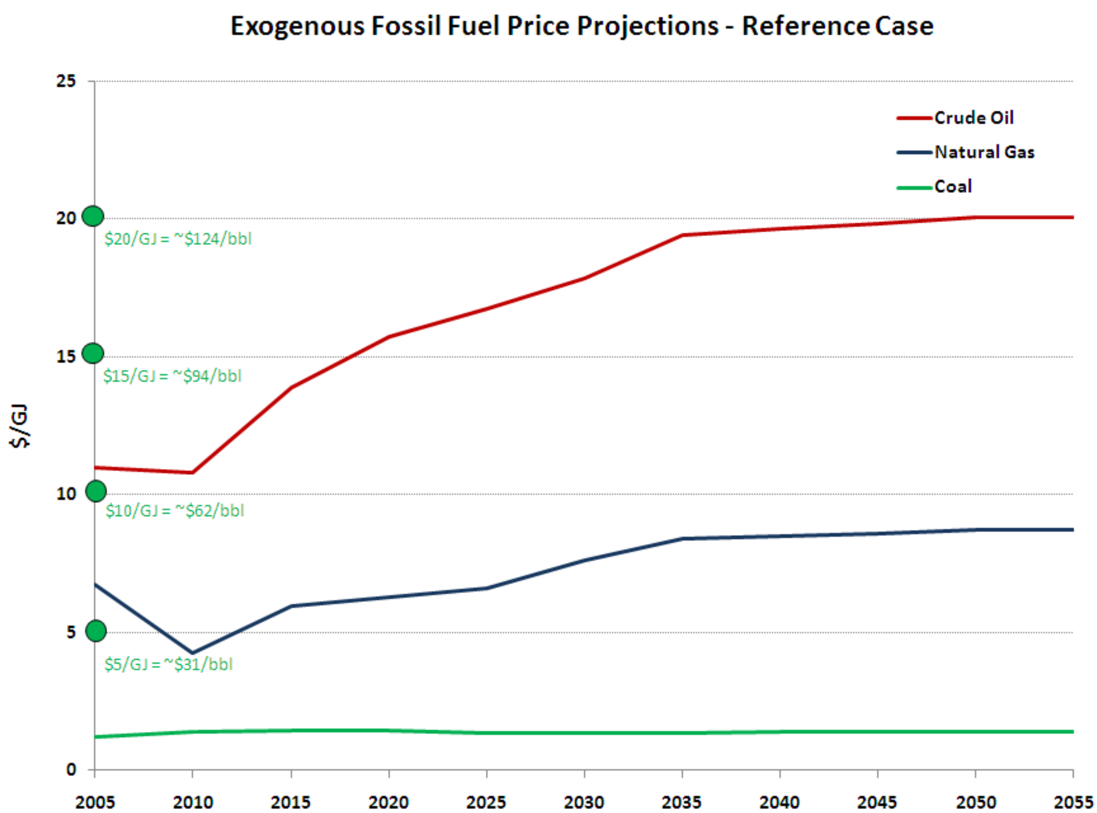


**Figure 25 Exogenous Fossil Fuel Price Projections in the Reference Case**

Biomass supply curves are based on work by Parker (2010). Two sets of his supply curves are used: one for biomass produced in California, and a second for biomass produced in the Western U.S. outside of California.[30] Unique supply curves exist for each of twelve different feedstock types. Presumably, all biomass produced in California will be available for consumption in the state. On the other hand, not all biomass in the Western U.S. will find its way to California in the form of raw biomass or, more likely, a liquid biofuel. In this latter case, an important assumption is made within CA-TIMES that only a fraction of Western U.S. biomass can be "captured" by the California market. This "fair share" assumption is varied in different scenarios, but in the Reference Case I assume a value of approximately 30%, which is roughly equivalent to California's current share (and projected future share) of Western U.S. population and liquid fuels consumption. As an illustration, Figure 26 sums up the availability of the various biomass feedstock types in 2050 in the Reference Case into an aggregate supply curve for both California and the Western U.S. Note that these costs only include biomass feedstock procurement; they do not include transport to a bio-refinery or power plant. In total, approximately 1,876 PJ of biomass are available for consumption in the California "energy system" in 2050. This is equivalent to roughly 117 million bone dry tons[31], or less than 10% of total sustainable biomass potential in the U.S., as estimated by the "Billion-Ton Study" (Perlack et al., 2005). For comparison, note that typical values for global sustainable biomass potential in 2050 are in the range of 50,000 to 150,000 PJ

[30] The Western U.S. is defined as all states in the continental U.S. (lower 48) that are west of the Mississippi River.

[31] This simplified calculation assumes an average biomass energy content of 16 GJ per bone dry ton, which is representative of typical forest residues, energy crops, and certain types of municipal solid waste.

(van Vuuren et al., 2010) – between 27 and 80 times the level assumed to be available for California consumption in the same year.

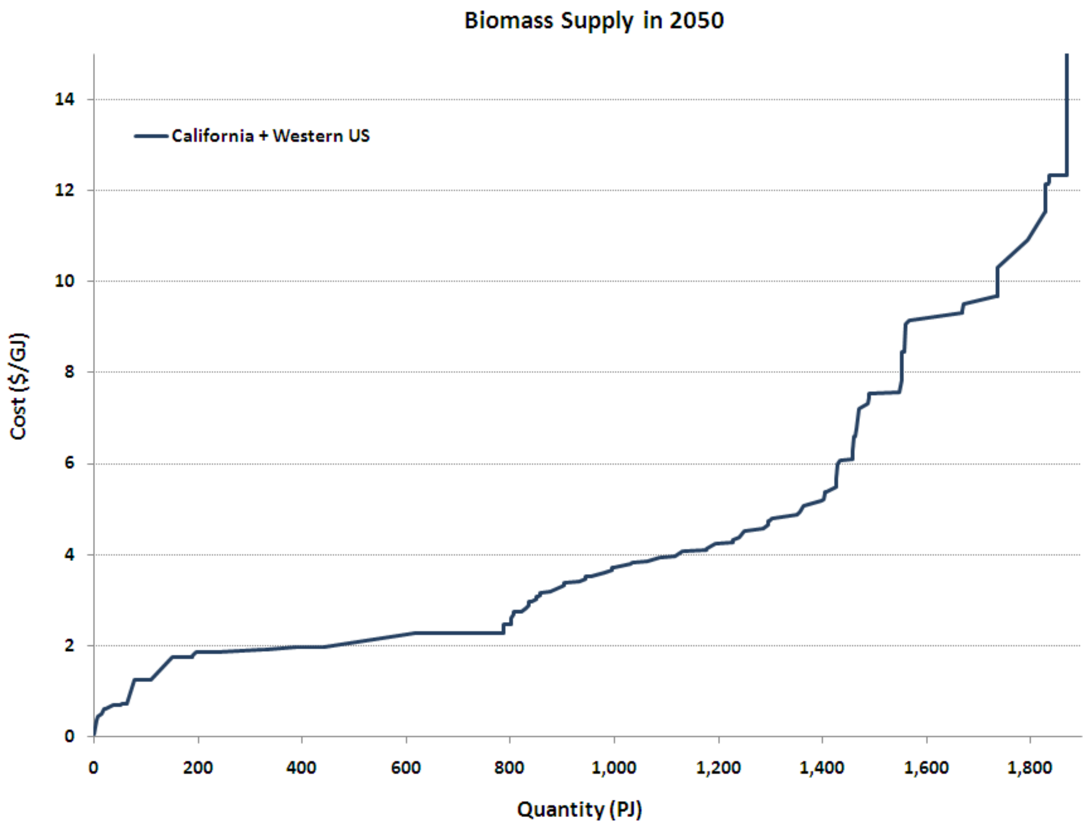


**Figure 26 Aggregate Supply Curve for All Types of Biomass Available in California and the Western U.S. in the Reference Case in 2050**

Investment cost and efficiency assumptions for refinery technologies are shown in Table 12 and Table 13, respectively.[32] As previously mentioned, California's existing refineries are able to expand production through a process known as "capacity creep". Such incremental growth is far less expensive than constructing a "greenfield" refinery on a brand new site. Refinery cost assumptions come from EIA (2006) and are consistent with those of EPA's US9r MARKAL model (EPA, 2008a). Efficiency assumptions for

[32] Investment costs are expressed in units of million dollars per annual input capacity ($/PJ-yr) because the refinery technologies are input-normalized in CA-TIMES.

existing refineries are calibrated to the base-year 2005, using data from the CEC's Energy Almanac (CEC, 2010a), the EIA Petroleum Navigator (EIA, 2010d), and the assumptions to the Petroleum Market Module of the EIA's NEMS model (EIA, 2010c). Efficiencies of future refineries are based on the latter. Note that refinery efficiencies are expressed in terms of the amount of energy consumed divided by crude oil feedstock consumption. In this sense, it is important to recognize that only a small portion of input crude oil is actually combusted at the refinery (~11%). The vast majority of the energy and carbon content of crude oil (i.e., the feedstock portion) is converted into fuel products, which are subsequently consumed/combusted in other sectors.

**Table 12 Investment Cost Assumptions for New Refining Capacity**

| Investment Costs for New Refining Capacity (M$/PJ-yr) *(Notes: Values apply to all model years.)* | |
|---|---|
| Existing Refinery ("Creep") | 4.61 |
| New Refinery ("Greenfield") | 18.43 |

**Table 13 Efficiency Assumptions for Refineries**

| Refinery Energy Consumption (PJ_Input / PJ_Oil-Feedstock) *(Notes: Values apply to all model years.)* | Crude Oil | Natural Gas | Natural Gas Liquids | Electricity |
|---|---|---|---|---|
| Existing Refinery | 1.110 | 0.019 | 0.019 | 0.003 |
| New Refinery | 1.110 | 0.014 | 0.019 | 0.004 |

The next several tables summarize the investment cost and efficiency assumptions for cellulosic ethanol, biodiesel, pyrolysis bio-oil, FT poly-generation, and hydrogen production plants and facilities.[33] Data sources and further information are discussed in Section II.2.2, but in general the characterizations of these fuel conversion technologies are based on studies by Bain (2007) and Kreutz et al. (2008), EPA (2008a), and NRC

[33] Investment costs are expressed in units of million dollars per annual output capacity ($/PJ-yr) because these fuel conversion technologies are output-normalized in CA-TIMES.

(2004). Note that, in contrast to the flexible refineries, the efficiencies of these technologies are expressed in terms of the amount of energy consumed divided by total plant output. Furthermore, because of the particular studies that were consulted in building up the technological representation of the CA-TIMES model, many of the fuel conversion technologies are represented by investment cost and efficiency assumptions that do not change over time. The assumptions shown in the tables below are the learned-out values, which are assumed to be achieved once the technology has matured and is commercially available at large-scale. Such representation is a bit different than for the electric generation and, in general, transportation technologies, for which costs and efficiencies are assumed to change gradually over time due to learning and experience. A potentially important impact of this difference in technological representation is on the rate of adoption of specific technologies. For instance, CA-TIMES results could show initial growth of these constant cost/efficiency technologies to be faster than what might ultimately be seen in reality, if the assumptions in the model turned out to be a bit too optimistic. In the later years, however, the opposite effect could be seen: the assumptions could turn to be too pessimistic.

**Table 14 Investment Cost Assumptions for New Cellulosic Ethanol Plants**

**Investment Costs for New Cellulosic Ethanol Plants (M$/PJ-yr)**

*(Notes: Values are interpolated between the data years shown.)*

| | 2005 | 2020 | 2035 | 2050 |
|---|---|---|---|---|
| **Biochemical Production Pathway** | | | | |
| All Biomass Feedstock Types (50 MGY) | 38.4 | 38.4 | 38.4 | 38.4 |
| All Biomass Feedstock Types (100 MGY) | 32.1 | 32.1 | 32.1 | 32.1 |
| **Thermochemical Production Pathway** | | | | |
| All Biomass Feedstock Types (50 MGY) | 42.3 | 42.3 | 42.3 | 42.3 |
| All Biomass Feedstock Types (100 MGY) | 34.9 | 34.9 | 34.9 | 34.9 |

Table 15  Investment Cost Assumptions for New Biodiesel Plants

| Investment Costs for New Biodiesel Plants (M$/PJ-yr) (Notes: Values are interpolated between the data years shown.) | 2005 | 2020 | 2035 | 2050 |
|---|---|---|---|---|
| All Biomass Feedstock Types (50 MGY) | 1.8 | 1.8 | 1.8 | 1.8 |
| All Biomass Feedstock Types (100 MGY) | 1.5 | 1.5 | 1.5 | 1.5 |

Table 16  Investment Cost Assumptions for New Pyrolysis Bio-Oil Plants

| Investment Costs for New Pyrolysis Bio-Oil Plants (M$/PJ-yr) (Notes: Values are interpolated between the data years shown.) | 2005 | 2020 | 2035 | 2050 |
|---|---|---|---|---|
| All Biomass Feedstock Types (25 MGY) | 15.1 | 15.1 | 15.1 | 15.1 |
| All Biomass Feedstock Types (100 MGY) | 10.2 | 10.2 | 10.2 | 10.2 |

Table 17  Investment Cost Assumptions for New FT Poly-Generation Plants

| Investment Costs for New FT Poly-Generation Plants (M$/PJ-yr) (Notes: Values are interpolated between the data years shown. Costs are the same for all biomass feedstock types.) | 2005 | 2020 | 2035 | 2050 |
|---|---|---|---|---|
| Biomass Gasification (61 MGY) | 96.1 | 96.1 | 72.1 | 72.1 |
| Biomass Gasification, w/ CCS (61 MGY) | 106.0 | 106.0 | 75.7 | 75.7 |
| Coal-Biomass Gasification, Syngas RC, w/ CCS (138 MGY) | 93.8 | 93.8 | 66.9 | 66.9 |
| Coal-Biomass Gasification, Syngas OT, w/ CCS (112 MGY) | 88.3 | 88.3 | 63.1 | 63.1 |
| Coal-Biomass Gasification, Syngas OT, w/ CCS (506 MGY) | 67.9 | 67.9 | 48.4 | 48.4 |

Table 18  Investment Cost Assumptions for New Hydrogen Production Facilities

| Investment Costs for New Hydrogen Production Facilities (M$/PJ-yr) (Notes: Values apply to all model years. ) | |
|---|---|
| **Centralized, Large-Size** | |
| Coal Gasification | 26.3 |
| Coal Gasification, w/ CCS | 26.9 |
| Natural Gas SMR | 11.0 |
| Natural Gas SMR, w/ CCS | 14.2 |
| **Centralized, Mid-Size** | |
| Natural Gas SMR | 24.5 |
| Natural Gas SMR, w/ CCS | 33.4 |
| Biomass Gasification | 138.0 |
| Biomass Gasification, w/ CCS | 141.2 |
| Water Electrolysis | 96.6 |
| **Distributed** | |
| Natural Gas SMR | 106.9 |
| Water Electrolysis | 144.8 |

Table 19 Efficiency Assumptions for New Cellulosic Ethanol Plants

| Cellulosic Ethanol Plant Biomass Consumption (PJ_Input / PJ_Output) (Notes: Values apply to all model years.) | | |
|---|---|---|
| **Biochemical Production Pathway** | | |
| Forest Residues | 50 MGY | 1.74 |
| | 100 MGY | 1.74 |
| Municipal Solid Waste, Paper | 50 MGY | 1.54 |
| | 100 MGY | 1.54 |
| Municipal Solid Waste, Wood | 50 MGY | 1.72 |
| | 100 MGY | 1.72 |
| Municipal Solid Waste, Yard | 50 MGY | 1.59 |
| | 100 MGY | 1.59 |
| Orchard and Vineyard Waste | 50 MGY | 1.69 |
| | 100 MGY | 1.69 |
| Pulpwood | 50 MGY | 1.74 |
| | 100 MGY | 1.74 |
| Agricultural Residues, Stovers/Straws | 50 MGY | 1.53 |
| | 100 MGY | 1.53 |
| Energy Crops | 50 MGY | 1.76 |
| | 100 MGY | 1.76 |
| **Thermochemical Production Pathway** | | |
| Forest Residues | 50 MGY | 2.12 |
| | 100 MGY | 2.12 |
| Municipal Solid Waste, Mixed | 50 MGY | 1.61 |
| | 100 MGY | 1.61 |
| Municipal Solid Waste, Paper | 50 MGY | 1.87 |
| | 100 MGY | 1.87 |
| Municipal Solid Waste, Wood | 50 MGY | 2.10 |
| | 100 MGY | 2.10 |
| Municipal Solid Waste, Yard | 50 MGY | 1.94 |
| | 100 MGY | 1.94 |
| Orchard and Vineyard Waste | 50 MGY | 2.05 |
| | 100 MGY | 2.05 |
| Pulpwood | 50 MGY | 2.12 |
| | 100 MGY | 2.12 |
| Agricultural Residues, Stovers/Straws | 50 MGY | 1.86 |
| | 100 MGY | 1.86 |
| Energy Crops | 50 MGY | 2.15 |
| | 100 MGY | 2.15 |

Table 20 Efficiency Assumptions for New Biodiesel Plants

| Biodiesel Plant Biomass Consumption (PJ_Input / PJ_Output) (Notes: Values apply to all model years.) | | |
|---|---|---|
| Yellow Grease | 50 MGY | 0.98 |
| | 100 MGY | 0.98 |
| Animal Tallow | 50 MGY | 1.03 |
| | 100 MGY | 1.03 |

**Table 21  Efficiency Assumptions for New Pyrolysis Bio-Oil Plants**

| Pyrolysis Bio-Oil Plant Biomass Consumption (PJ_Input / PJ_Output) *(Notes: Values apply to all model years.)* | | |
|---|---|---|
| | | |
| **Forest Residues** | **25 MGY** | 1.59 |
| | **100 MGY** | 1.59 |
| **Municipal Solid Waste, Mixed** | **25 MGY** | 1.20 |
| | **100 MGY** | 1.20 |
| **Municipal Solid Waste, Paper** | **25 MGY** | 1.40 |
| | **100 MGY** | 1.40 |
| **Municipal Solid Waste, Wood** | **25 MGY** | 1.57 |
| | **100 MGY** | 1.57 |
| **Municipal Solid Waste, Yard** | **25 MGY** | 1.45 |
| | **100 MGY** | 1.45 |
| **Orchard and Vineyard Waste** | **25 MGY** | 1.53 |
| | **100 MGY** | 1.53 |
| **Pulpwood** | **25 MGY** | 1.59 |
| | **100 MGY** | 1.59 |
| **Agricultural Residues, Stovers/Straws** | **25 MGY** | 1.39 |
| | **100 MGY** | 1.39 |
| **Energy Crops** | **25 MGY** | 1.61 |
| | **100 MGY** | 1.61 |

**Table 22 Efficiency Assumptions for New FT Poly-Generation Plants**

| FT Poly-Generation Plant Energy Consumption (PJ_Input / PJ_Output)<br>*(Notes: Values apply to all model years.)* | | | |
|---|---|---|---|
| | | **Biomass** | **Coal** |
| **Biomass Gasification (61 MGY)** | **Forest Residues** | 1.88 | 0.00 |
| | **Municipal Solid Waste, Mixed** | 1.43 | 0.00 |
| | **Municipal Solid Waste, Paper** | 1.66 | 0.00 |
| | **Municipal Solid Waste, Wood** | 1.86 | 0.00 |
| | **Municipal Solid Waste, Yard** | 1.72 | 0.00 |
| | **Orchard and Vineyard Waste** | 1.82 | 0.00 |
| | **Pulpwood** | 1.88 | 0.00 |
| | **Agricultural Residues, Stovers/Straws** | 1.65 | 0.00 |
| | **Energy Crops** | 1.91 | 0.00 |
| **Biomass Gasification, w/ CCS (61 MGY)** | **Forest Residues** | 1.94 | 0.00 |
| | **Municipal Solid Waste, Mixed** | 1.47 | 0.00 |
| | **Municipal Solid Waste, Paper** | 1.72 | 0.00 |
| | **Municipal Solid Waste, Wood** | 1.92 | 0.00 |
| | **Municipal Solid Waste, Yard** | 1.78 | 0.00 |
| | **Orchard and Vineyard Waste** | 1.88 | 0.00 |
| | **Pulpwood** | 1.94 | 0.00 |
| | **Agricultural Residues, Stovers/Straws** | 1.70 | 0.00 |
| | **Energy Crops** | 1.97 | 0.00 |
| **Coal-Biomass Gasification, Syngas RC, w/ CCS (138 MGY)** | **Forest Residues** | 0.83 | 1.14 |
| | **Municipal Solid Waste, Mixed** | 0.63 | 1.14 |
| | **Municipal Solid Waste, Paper** | 0.74 | 1.14 |
| | **Municipal Solid Waste, Wood** | 0.82 | 1.14 |
| | **Municipal Solid Waste, Yard** | 0.76 | 1.14 |
| | **Orchard and Vineyard Waste** | 0.81 | 1.14 |
| | **Pulpwood** | 0.83 | 1.14 |
| | **Agricultural Residues, Stovers/Straws** | 0.73 | 1.14 |
| | **Energy Crops** | 0.84 | 1.14 |
| **Coal-Biomass Gasification, Syngas OT, w/ CCS (112 MGY)** | **Forest Residues** | 0.76 | 1.30 |
| | **Municipal Solid Waste, Mixed** | 0.58 | 1.30 |
| | **Municipal Solid Waste, Paper** | 0.67 | 1.30 |
| | **Municipal Solid Waste, Wood** | 0.75 | 1.30 |
| | **Municipal Solid Waste, Yard** | 0.70 | 1.30 |
| | **Orchard and Vineyard Waste** | 0.73 | 1.30 |
| | **Pulpwood** | 0.76 | 1.30 |
| | **Agricultural Residues, Stovers/Straws** | 0.67 | 1.30 |
| | **Energy Crops** | 0.77 | 1.30 |
| **Coal-Biomass Gasification, Syngas OT, w/ CCS (506 MGY)** | **Forest Residues** | 0.17 | 1.95 |
| | **Municipal Solid Waste, Mixed** | 0.13 | 1.95 |
| | **Municipal Solid Waste, Paper** | 0.15 | 1.95 |
| | **Municipal Solid Waste, Wood** | 0.17 | 1.95 |
| | **Municipal Solid Waste, Yard** | 0.16 | 1.95 |
| | **Orchard and Vineyard Waste** | 0.17 | 1.95 |
| | **Pulpwood** | 0.17 | 1.95 |
| | **Agricultural Residues, Stovers/Straws** | 0.15 | 1.95 |
| | **Energy Crops** | 0.18 | 1.95 |

**Table 23 Efficiency Assumptions for New Hydrogen Production Facilities**

| Hydrogen Production Facility Feedstock Consumption (PJ_Input / PJ_Output) | | |
|---|---|---|
| *(Notes: Units are in PJ_Input per PJ_Output, except for water electrolysis for which the primary feedstock is liquid $H_2O$, and consumption is in million liters per PJ_output. Energy consumption is the same for all biomass feedstock types. Values apply to all model years.)* | | |
| | **Primary Feedstock** | **Electricity** |
| **Centralized, Large-Size** | | |
| **Coal Gasification** | 1.39 | 0.07 |
| **Coal Gasification, w/ CCS** | 1.39 | 0.11 |
| **Natural Gas SMR** | 1.04 | 0.02 |
| **Natural Gas SMR, w/ CCS** | 1.10 | 0.05 |
| **Centralized, Mid-Size** | | |
| **Natural Gas SMR** | 1.10 | 0.03 |
| **Natural Gas SMR, w/ CCS** | 1.15 | 0.07 |
| **Biomass Gasification** | 2.69 | 0.19 |
| **Biomass Gasification, w/ CCS** | 2.68 | 0.27 |
| **Water Electrolysis** | 156.77 | 1.63 |
| **Distributed** | | |
| **Natural Gas SMR** | 1.32 | 0.07 |
| **Water Electrolysis** | 156.77 | 1.65 |

*Transportation Sector*

### Base-Year 2005 Fuel Consumption

Base-year 2005 fuel consumption in each of the CA-TIMES transport subsectors and segments are estimated by a variety of means and sources – mostly by using the CARB GHG Inventory (CARB, 2010b), but in some cases other data sources are used to supplement, as described below. The historical figures are typically provided in their native units (e.g., gallons gasoline, gallons diesel, standard cubic feet of natural gas, etc.); these can then be converted to common units, such as petajoules (PJ).

For gasoline, diesel, and ethanol consumption by on-road transportation vehicles (i.e., light-duty passengers cars and trucks, heavy- and medium-duty trucks and buses, and motorcycles), historical fuel consumption estimates are based on a combination of data provided by the CARB GHG Inventory (CARB, 2010b), the California Energy

Commission (CEC, 2007) and the California Department of Transportation (Caltrans, 2006). Similarly, natural gas consumption for on-road passenger vehicles is taken from the CARB GHG Inventory.

Consumption of kerosene-type jet fuel for commercial passenger and freight aviation is calculated from data that was used to develop the CARB GHG Inventory estimates (CARB, 2008b). More specifically, I utilize air carrier data to estimate the number of flights within, into, and out of California (both domestic and international). Then, based on plane types and trip distances, fuel consumption is estimated. For general aviation[34], data on jet fuel and aviation gasoline consumption is obtained from the Federal Aviation Administration (FAA, 2007).

Diesel and residual fuel oil consumption for California marine transport is taken from the CARB GHG Inventory.

Diesel fuel consumption by California railways in 2005 is based on statistics from the U.S. DOT's National Transit Database for commuter, heavy, and light rail (DOT, 2006a). For intercity and freight rail, diesel fuel consumption is estimated based on California's share of intercity passenger-miles and freight ton-miles, respectively. California intercity passenger-miles are estimated by using Amtrak passenger boardings as a proxy, specifically the share of California passenger boardings in the U.S. total (DOT, 2007b). The share of freight rail ton-miles that originated in California compared to the entire U.S. is obtained from DOT data as well (DOT, 2006b).

[34] General aviation includes personal and corporate jets and other small propeller aircraft.

Electricity consumption for transportation is also taken from the National Transit Database (DOT, 2006a). First, the data are filtered for California transit agencies only, and then electricity consumption is estimated for each transit vehicle type. The data shows that in 2005, electricity was only consumed by the following vehicle types: cable car, heavy rail, light rail, bus, and trolleybus. Note that these figures do not include electricity consumption for Amtrak trains, which is understandable since no Amtrak trains use electricity in California – they are all diesel-powered. The data does not appear to include electricity consumption for recharging of personal electric vehicles (such as passenger cars, light-duty trucks, neighborhood electric vehicles, golf carts, etc.); though, in 2005 these demands were very small in comparison to other transportation electricity demands.

Gasoline, diesel, and natural gas consumption for off-road and construction, agricultural vehicles, and personal recreational boats are estimated by using data obtained by running CARB's OFFROAD2007 model for the year 2005 and then performing some subsequent calculations and data aggregation (CARB, 2007d). For consumption of liquefied petroleum gases (LPG), the CARB GHG Inventory is used.

California biodiesel consumption in 2005 is not listed in the GHG Inventory, so I estimate it independently by assuming that California's biodiesel consumption is approximately 10% of the national total, which was 75 million gallons biodiesel in 2005 (NBD, 2007). Thus, California consumed about 7.5 million gallons in 2005, a figure that is corroborated by the City and County of San Francisco Biodiesel Access Task Force, who estimate that California biodiesel consumption was about 7 million gallons in 2005 (SFBATF, 2006). Furthermore, it is assumed that in the base-year all biodiesel is consumed by heavy-duty vehicles (trucks and buses); obviously, this ignores the very small quantity of biodiesel consumed by passenger cars and light-duty trucks.

## Base-Year 2005 Activity Demands and Vehicle Stocks

The calibration of base-year transport sector energy demands in CA-TIMES requires data on transport service demand, i.e., activity, (passenger-miles, vehicle-miles, ton-miles, etc.), vehicle stocks (cars, trucks, aircraft, ships, trains, etc.), and other data (e.g., passengers per vehicle, freight tons per train). In some cases these statistics are obtained specifically for California; however, in other cases the data are approximated for California based on aggregate U.S. data.

### *Light-duty Cars and Motorcycles*

The unit of activity is vehicle-miles of travel (VMT). For cars, this data is obtained from CEC IEPR 2007 estimates (CEC, 2007). For motorcycles, it is taken from the Caltrans 2006 MVSTAFF report (Caltrans, 2006). Further, I was able to find data on the number of motorcycles in California and the annual average mileage of those vehicles by running CARB's EMission FACtors (EMFAC2007) model (CARB, 2007c). Note that EMFAC data on vehicle stocks originally come from California Department of Motor Vehicle (DMV) registration data. Stocks and annual mileages of conventional gasoline ICE vehicles and gasoline hybrid-electric vehicles are obtained from the CEC IEPR estimates.

The IEPR data shows that the number of diesel cars in California was zero in 2005; however, EMFAC shows otherwise. Therefore, the EMFAC data is used to estimate the number of diesel cars and their average annual mileage. Moreover, while EMFAC shows that there were a very small number of electric vehicles operating in California in 2005, I have ignored these vehicles here since their contribution to overall base-year energy demands is trivial, and little information exists about these vehicles. In contrast, I have not been able to find any consistent data on the stock and total mileage of all natural gas vehicles in California, so this category is also ignored in the base-year 2005.

Fuel economies for cars and motorcycles vary widely by vehicle type and model. Yet, for the purposes of calibrating base-year transport sector energy demands, only average fuel economy values are needed for gasoline ICE cars, gasoline HEV cars, diesel cars, and gasoline ICE motorcycles. These averages are obtained from the CEC IEPR and Caltrans MVSTAFF data.

All light-duty cars and motorcycles are assumed to have a lifetime of 15 years, consistent with assumptions used in the EPA 9-region MARKAL model for the U.S. The vehicle types, like all technologies in CA-TIMES are “vintaged”, meaning that the technological assumptions that apply to the technology in the year of its introduction continue to apply throughout the technology’s lifetime.

### *Light-Duty Trucks*

Activity data (in VMT) for light-duty trucks is obtained from CEC IEPR 2007 estimates. The number of light-duty trucks in California and the annual average mileage of those vehicles are also taken from IEPR for conventional gasoline vehicles and gasoline HEVs. For diesel light-duty trucks, the data comes from running CARB's EMFAC model. In EMFAC, we consider the truck categories T1, T2, T3, and T4 to be light-duty trucks. These categories include trucks that are less than 10,000 pounds in weight, which is slightly different from the CAFE-defined 8,750 pound maximum weight for light-duty trucks but is consistent with definitions found elsewhere for "light-duty trucks". Note that because the number of electric and natural gas light-duty trucks was so small in the base-year (or data on them could not be found), these vehicle types are ignored. Average fuel economies for gasoline and gasoline HEV light-duty trucks are obtained from the CEC IEPR data. The average fuel economy of diesel light-duty trucks in California comes from the CalTrans MVSTAFF report.

All light-duty trucks are assumed to have a lifetime of 15 years, consistent with assumptions used in the EPA 9-region MARKAL model for the U.S.

### *Heavy-Duty and Medium-Duty Trucks*

The EMFAC model is the source for total vehicle miles of travel, vehicle stock, and average annual mileage per vehicle for both medium- and heavy-duty trucks. Medium-duty trucks include EMFAC truck categories T5 and T6, corresponding to trucks with weights between 10,000 and 33,000 pounds. Heavy-duty trucks include category T7, with weights from 33,000 to 60,000 pounds. While there are a larger number of medium-duty trucks than heavy-duty trucks in California, they are typically used for shorter-distance travel, and they are more efficient. Hence, heavy-duty trucks account for greater quantities of total vehicle-miles and fuel consumption. Average fuel economies for the two vehicle categories are obtained from CalTrans MVSTAFF.

Heavy-duty trucks are assumed to have a lifetime of between 15 and 20 years, depending on technology, consistent with assumptions used in the IEA-ETP global MARKAL model. Medium-duty trucks have lifetimes of 10-20 years. In both cases, vehicles with compression-ignition (i.e., diesel) engines have longer lifetimes, while spark-ignition (i.e., gasoline) vehicles and other alternative-fuel vehicles have shorter lifetimes.

### *Buses*

The bus subsector is comprised of three distinct segments: transit buses, school buses, and other buses, the latter of which includes intercity buses. The activity unit for all bus types is vehicle-miles traveled. All transit bus statistics come from either the National Transit Database or EMFAC. The number of school buses in operation in California is given by *School Transportation News* (STN, 2007). Data on school bus passenger-miles (PMT) for the entire U.S. comes from *The Public Purpose* (The Public Purpose, 2007). The share of school buses in California versus the entire U.S. (about 5.5%) is then used to estimate California's total school bus PMT. School bus VMT is given by EMFAC. All data on other types of buses, which include intercity (e.g., Greyhound) buses, are taken from EMFAC. Average fuel economies of the different bus types are calculated based on the fuel consumption and VMT estimates discussed above.

Transit, school, and other/intercity buses are all assumed to have a lifetime of between 15 and 20 years, depending on technology, consistent with assumptions used in the IEA-ETP global MARKAL model. As with trucks, vehicles with compression-ignition (i.e., diesel) engines have longer lifetimes, while spark-ignition (i.e., gasoline) vehicles and other alternative-fuel vehicles have shorter lifetimes.

*Rail*

There are five different types of rail transport in California. Passenger rail includes commuter, heavy, light, and intercity (e.g., Amtrak) rail. The activity unit for these passenger modes is PMT. The other type of rail transport is freight rail, the activity unit for which is ton-miles. The National Transit Database provides statistics on total PMT, VMT, train-miles traveled (TMT), and vehicle stocks for commuter, heavy, and light rail (where a 'train' refers to a collection of a number of individual rail 'vehicles', i.e., locomotives and/or rail cars). "Light rail" includes both traditional light rail street cars, as well as historic cable cars in San Francisco. In California all heavy rail (e.g., BART) and light rail systems are completed electrified. In contrast, commuter, intercity, and freight rail trains in California tend to use diesel-powered locomotives. For intercity rail, as mentioned above, California passenger-miles, vehicle-miles, and train-miles, as well as the stock of locomotives and rail cars in California, are estimated by using Amtrak statistics (DOT, 2007b). Similarly, freight rail ton-miles, vehicle-miles, train-miles, and vehicle stocks are estimated using the share of ton-miles originated in California compared to the entire U.S. (DOT, 2006b, 2007a). From these data I was able to calculate several useful metrics reflective of rail operations, including the number of passengers per rail vehicle, vehicles per train, passengers per train, and average train-miles per train per year, as well as energy intensities for each type of vehicle.

All types of rail equipment (i.e., locomotives and rolling stock for both passenger and freight trains) are assumed to have lifetimes of 20 years, consistent with assumptions used by the EPAUS9r and IEA-ETP.

### *Marine*

The activity unit for domestic marine transport (both intrastate and interstate) via large shipping vessels is ton-miles. Yet, because I could only find data on marine ton-miles for the entire U.S., California's share of marine tons is used a proxy for ton-miles. The amount of tons shipped by large shipping vessels to intrastate, interstate, and foreign markets is obtained from the U.S. Army Corps of Engineers (USACE, 2007). California's share of intrastate tons shipped (i.e., originated) is about 4.9% of the U.S. total. When considering interstate shipments that either originate or terminate in California, the weighted average share is about 3.9%. I use this latter share to estimate the number of large shipping vessels in operation in the state and the amount of ton-miles shipped by these vessels. National level data are taken from the ORNL Transportation Energy Data Book (ORNL, 2010). The shares of marine tons shipped to intrastate and interstate markets (from USACE) are then used to estimate the number of large shipping vessels used for both intrastate and interstate marine transport. Interstate trade comprises about 70% of domestic marine tons (and thus vessels and ton-miles by our calculations) while the other 30% is intrastate. The energy intensity of California large shipping vessels is assumed to be the same as the national average value found in the ORNL Data Book.

Harbor craft[35] and personal recreational boats are two other types of domestic marine vehicles that operate within the state's boundaries. The unit of activity for both of these intrastate categories is hours of operation. Data on harbor craft activity, stock, and energy intensity are calculated from CARB's Statewide Commercial Harbor Craft Survey (CARB, 2004). Data on personal boats come from running CARB's OFFROAD2007 model for the year 2005, then aggregating the output and estimating vehicle stocks, activity (hours of operation per year), and energy intensities (gallons of fuel per hour).

The unit of activity for large marine vessels operating internationally is vessel-miles. The data for these vehicle types, including vessel stock, come from CARB's 2005 Oceangoing Ship Survey (see "Appendix C: Summary of Results" and "Appendix D: Emissions Estimation Methodology for Ocean-Going Vessels") (CARB, 2005). According to the survey, about 99% of today's large marine vessels use residual fuel oil as the main fuel for their propulsion systems, while the remaining 1% use diesel. Using data provided by the CARB survey report on emissions, average speed, and average propulsion system power by type of oceangoing vessel, I estimate the total number of

[35] Harbor craft are vessels used for commercial purposes or to support public services. There are several types of harbor craft including crew and supply boats, charter fishing vessels, commercial fishing vessels, ferry/excursion vessels, pilot vessels, towboat or push boats, tug boats and work boats.

vessel-miles traveled by these vessels in 2005, average annual mileage of the vessels, and fuel consumption per vessel-mile by.

Large shipping vessels, large marine vessels, and harbor craft are assumed to have lifetimes of 30 years, based on EPAUS9r values, while personal recreational boats are assumed to have lifetimes of 20 years.

### *Aviation*

Information on commercial flights within, leaving from, and arriving to California are obtained from CARB staff in spreadsheet database format (CARB, 2008b). This data was originally obtained from DOT's Research and Innovative Technology Administration's (RITA) Form 41 Traffic database of air carrier statistics. CARB filtered this data for California and then organized it by type of flight – intrastate (CA to CA), interstate (CA to US, US to CA), and international (CA to World, World to CA). The database provides fairly detailed information for every single flight within these categories in 2005, for example, origin and destination airport, number of passengers, weight of freight, distance of flight, type of airplane, and so on. From this data, the total number of passenger-miles and freight ton-miles was estimated for California in 2005 for each of the different types of flights. Airplane stocks were determined by using as a proxy the share of California airplane-miles in the U.S. total (DOT, 2007c). In reality, airplanes cannot be said to "belong" to California or any other state. Yet, for the purposes of accounting and calibrating stock, passenger-mile, and ton-mile data to base-year fuel demands, it is necessary to roughly estimate the number of "airplane-equivalents" operating solely within California energy system in a given year – i.e., on intrastate, interstate, and international routes for both passenger and freight aviation.

The unit of activity for general aviation is hours of operation. I assume that general aviation operates completely within the state (i.e., only intrastate trips are possible), which is likely not true in all cases, for example, with personal and corporate jets. Nevertheless, because no specific data on general aviation flight movements could be found (all data is aggregated) the assumption of general aviation being in the intrastate aviation category is made. I recognize that this introduces a small amount of error into the model, though it is fairly trivial when considering that general aviation activity and fuel demands pale in comparison to commercial passenger and freight aviation. As with jet fuel and aviation gasoline consumption for general aviation aircraft, all transport activity and energy intensity data is obtained from the FAA (FAA, 2007). Some California-specific data is available in the survey, but most is for the entire U.S. Thus, the share of general aviation aircraft in operation in California and the share of hours of operation, both compared to U.S. totals, are used as proxies for estimating other values, such as the number of jet aircraft vs. propeller aircraft.

A third category of aviation includes other/miscellaneous aircraft flights and energy usage. This category is part of the CARB GHG Inventory, and according to earlier conversations with CARB staff, it is unclear what the category actually comprises (CARB, 2008c). Military flights are included, as is fuel used for ground operations at airports. Part of the category could also include activity and fuel use that should be a part of the passenger, freight, and general aviation categories but was not included because of errors in the calculations. In other words, the other/miscellaneous category probably includes some remainder values from other categories. Due to these data uncertainties, I make some simplifications in modeling this other/miscellaneous aviation category. First, the unit for activity is in fictional "activity units", and the level of activity in the base-year 2005 is arbitrarily specified to be 100 activity units. Then, efficiency (in activity units per PJ) is estimated by dividing the fictional activity units by this category's total fuel use in 2005, which is known from the CARB GHG Inventory.

Base-year aviation technologies of all types are assumed to have lifetimes of 20 years, consistent with EPAUS9r assumptions, whereas future aviation technologies have lifetimes of 30 years, consistent with IEA-ETP assumptions.

### *Off-Road & Construction Devices*

The unit of activity for off-road and construction vehicles[36] is hours of operation, which is fitting given that some of these vehicles never actually move anywhere, so they are not "transport vehicles" in the strictest sense of the phrase. Data on total hours of vehicle operation, vehicle stocks by fuel type (gasoline, diesel, and LPG/CNG), and average annual hours of operation by fuel type all come from running CARB's OFFROAD2007 model, then aggregating the output and performing some subsequent calculations

[36] The off-road & construction subsector is comprised of a diverse set of vehicles including (to name just a few) off-road motorcycles, snowmobiles, all-terrain vehicles (ATVs, 4-wheelers), golf carts, cranes, forklifts, loaders, tractors, backhoes, excavators, dumpers, dredgers, aerial lifts, sweepers and scrubbers, riding lawn mowers, lawn and garden tractors, cargo tractors, and various types of airport vehicles (A/C tugs, baggage tugs, cargo loaders, deicers, forklifts, fuel trucks, ground power units, maintenance trucks, catering trucks, lavatory trucks, water and hydrant trucks).

(CARB, 2007d). Energy intensity estimates are similarly obtained. Note that the overwhelming majority of off-road vehicles in California are gasoline-powered. Yet, because diesel vehicles consume so much fuel on a per hour basis, diesel fuel consumption is quite a bit higher than either gasoline or natural gas consumption. Because different fuels are used for different vehicle types, I divide this category up into three subcategories based on fuel type.

All off-road and construction technologies are assumed to have a lifetime of 25 years, consistent with EPAUS9r assumptions.

*Agricultural Vehicles*

The unit of activity for off-road and construction vehicles[37] is also hours of operation. As for off-road and construction vehicles, data on agricultural vehicles is obtained from running OFFROAD2007. Both gasoline and diesel are used in agricultural vehicles, and in terms of vehicle stocks, they are roughly equivalent. However, since fuel consumption per hour is much higher for diesel vehicles (presumably because they are larger), diesel fuel consumption is an order of magnitude larger than gasoline consumption. As with off-road and construction vehicles, I divide agricultural vehicles up into two categories based on fuel type.

All agricultural vehicle technologies are assumed to have a lifetime of 25 years, consistent with EPAUS9r assumptions.

[37] The agricultural vehicle subsector is comprised of a diverse set of vehicles including tractors, combines, balers, mowers, sprayers, tillers, and swathers.

### *Pipelines*

Natural gas consumption for both natural gas and non-natural gas pipelines in California is taken from the EIA (EIA, 2010b). The unit of activity for pipeline natural gas consumption is assumed to be total California natural gas consumption in any given year, which is also obtained from the same source. In 2005, approximately 0.00479 scf of pipeline natural gas were consumed for every 1 scf of total natural gas transported (or alternatively, 0.00479 PJ per PJ). By this metric, the relative consumption of natural gas for pipeline compressors is extremely small. Note that this transport subsector is treated differently from the other subsectors since there is no stock or annual average activity *per se*.

## Service Demand Projections

In CA-TIMES, future-year projections of demand (e.g., vehicle-miles, passenger-miles, ton-miles, vessel-miles, hours of operation, and so on) are exogenously specified. This section discusses the key input assumptions and data sources for developing reference case demand projections for the various transport subsectors.

### *Light-Duty Cars and Trucks*

Total combined light-duty car and truck VMT in California is projected into the future by applying annual growth rates for U.S. VMT per capita, which come from the EIA's AEO2010 Reference Case projections (see Table 60 of AEO2010) (EIA, 2010a)[38], and

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[38] Note that in order to extrapolate out to later years, I assume the average annual percentage growth rate in per-capita VMT declines from the mean 2025-2030 value down to 0.5% per year in 2050. Such a gradual

applying these rates to the base-year 2005 numbers from CEC. Similarly, car-truck share splits are projected into the future, using the EIA's projected changes for the U.S. light-duty stock (see Table 58 of AEO2010). With these two time series, the trajectories for both light-duty car and light-duty truck VMT can be calculated. These trajectories are shown in Figure 27.

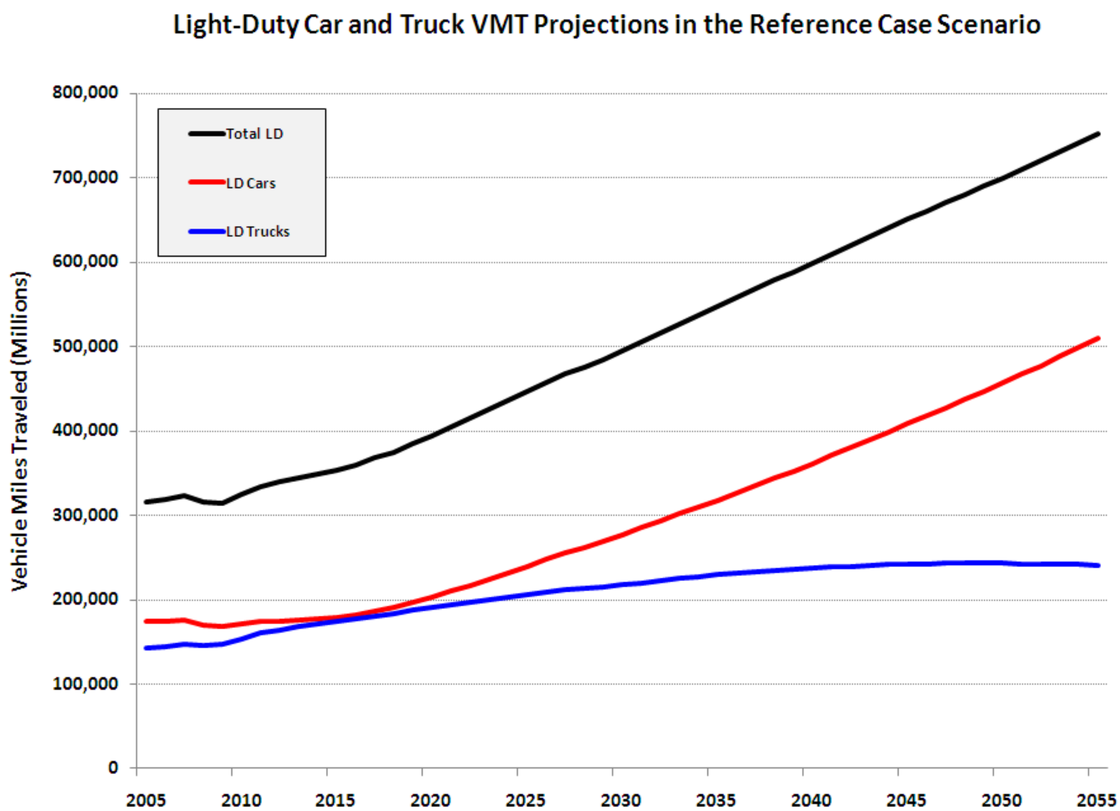


**Figure 27 Light-Duty Car and Truck VMT Projections in the Reference Case Scenario**

*Motorcycles*

Projections for on-road motorcycle demand between 2005 and 2030 are calculated based on growth rates from Caltrans (2009). Then, because base-year demands are derived

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decline is meant to represent an increasing saturation of private auto travel in California, as the population grows, densities increase, and congestion continues to get worse.

from EMFAC model results, the Caltrans growth rates are applied to the 2005 EMFAC numbers. For the post-2030 time period, extrapolation is done by using the average annual percentage growth rate between 2020 and 2030 and applying it to the later years as a constant growth rate.

### *Heavy-Duty and Medium-Duty Trucks*

As is the case with motorcycles, base-year VMT demands are projected into the future, using growth rates from Caltrans (2009). Note that Caltrans' definition for medium-duty trucks ('Truck3' in the MVSTAFF report) is the same as the EMFAC truck categories T5 and T6 (vehicle weights of 10,000 – 33,000 pounds). Similarly, heavy-duty trucks ('Truck4' in Caltrans MVSTAFF) are equivalent to the EMFAC truck category T7 (greater than 33,000 pounds).

### *Buses*

Because I was unable to find any reliable estimates of future California bus demands, I simply assume that the demands in the three bus segments each scale with population. California population projections are taken from the California Department of Finance (DOF, 2007).

### *Rail*

Rail PMT and TMT in California is projected into the future by applying annual growth rates for energy use by rail segment for the entire U.S. These projections come from the EIA's AEO2010 Reference Case projections (see Supplemental Table 45 of AEO2010).

In doing this, I am effectively using rail energy growth as a proxy for demand growth, which is of course an approximation, though a necessary one given the absence of projections from any other sources.

*Marine*

For most of the marine segments (namely, domestic-intrastate and domestic-interstate large shipping vessels, harbor craft, and personal recreational boats), annual growth rates from AEO2010 are used to project ton-miles or hours of vehicle operation, whatever the case may be (see Supplemental Tables 7 and 67 of AEO2010). In some cases, energy use is taken as a proxy for demand. In contrast, for international large marine vessels, a different approach is utilized. In short, vessel population projections estimated by Dr. James Corbett (University of Delaware) are used as a proxy for future vessel-miles (see Appendix D of CARB's Oceangoing Ship Survey report, p. D-18) (CARB, 2005).

*Aviation*

For domestic and international freight and passenger aviation, national-level projections (in passenger-miles and ton-miles, respectively) are used to project California's future commercial aviation demands (see Supplemental Table 66 of AEO2010). Growth rates are estimated for each category of air travel and then applied to California's base-year demands. The domestic passenger and freight projections from AEO are assumed to be applicable to both domestic-intrastate and domestic-interstate aviation in California. General aviation demand is projected into the future using national-level projections of general aviation energy use as a proxy for hours of operation (see Supplemental Table 66 of AEO2010). It is important to note that this approximation masks any future shifts between jet-powered and propeller airplanes, as well as the changing efficiency and usage (in terms of hours per year) of those planes. The error this introduces to the model is relatively small, since general aviation demands are so minimal compared to the other aviation segments. For the other/miscellaneous aviation category, the growth rate in future activity is tied to growth in the U.S. population.

### *Off-Road & Construction Devices*

Projections for off-road and construction activity in the three different demand segments are estimated using CARB's OFFROAD2007 model (CARB, 2007d). First, I run the model for the years 2005 and 2040, in order to obtain demand and fuel use. Then, I interpolate and extrapolate for all other years in the modeling horizon.

### *Agricultural Vehicles*

Projections for agricultural vehicle activity are calculated in the same way as for off-road and construction devices by using CARB's OFFROAD2007 model.

### *Pipelines*

Future consumption of pipeline natural gas depends on the total quantity of natural gas demanded/transported in California in the future. This, of course, depends on the particular scenario being run. Therefore, projections for pipeline natural gas demand must be continually updated so that the exogenously specified trajectories are in line with the endogenous demands for natural gas that are calculated by the model in a given model run.

**Light-duty Vehicle Cost and Efficiency Assumptions**

The following tables summarize the cost and efficiency assumptions for all light-duty vehicle technologies that are available to the CA-TIMES model in any future year. For the most part, the baseline assumptions come from the EIA's AEO2010 Reference Case assumptions and projections (EIA, 2010a, c). Investment costs refer to the average price that a consumer would expect to pay for a vehicle.

In certain cases, a handful of other sources are used to modify the EIA numbers data. For instance, Moderate and Advanced Gasoline Internal Combustion Engine (ICE) vehicles are not represented in the AEO2010. Instead, I have created these two technologies to capture the potential for efficiency improvements in the light-duty sector. These vehicles are simply conventional gasoline ICEs that achieve higher fuel economies (on the order of 15% to 30%) due to a suite of incremental efficiency enhancements, which necessitate small, but nontrivial, increases in the investment costs relative to the conventional Gasoline ICE. The technology characterizations for Moderate and Advanced Gasoline ICEs are based on unpublished data from the U.S. EPA Office of Transportation and Air Quality (OTAQ) by way of the EPA's US9r MARKAL model (EPA, 2008a). Similarly, I have also added several E-85 Flex Fuel vehicle technologies beyond those represented in AEO2010 (e.g., E-85 Moderate ICEs, Advanced ICEs, HEVs, and PHEVs). In all cases, the efficiencies of these technologies are the same as for their comparable gasoline counterparts, while investment costs are based on the incremental cost increase of AEO2010's standard E-85 Flex Fuel vehicle relative to the conventional Gasoline ICE (typically less than $1,000). Only Gasoline PHEVs with 10- and 40-mile all-electric ranges are represented in AEO2010; however, as the tables below indicate, I also make PHEV 30s and 60s available to the model, as well as E-85 Flex Fuel and Diesel PHEVs with 10-, 30-, 40-, and 60-mile all-electric ranges. In short, to make these technology characterizations, I use the AEO2010 cost estimates for PHEV 10s and 40s to approximate the cost of PHEV 30s and 60s, assuming the same per-kWh battery costs. (Note that in the AEO2010 Reference Case, the cost of lithium-ion batteries is assumed to level out at $500/kWh by 2030. Fuel cell costs are assumed to drop to $139/kW by 2030 and $55/kW by 2050.) Then, I take the incremental cost increases of the Gasoline PHEV 10/30/40/60s compared to a Gasoline HEV and apply these to the E-85 Flex Fuel HEV and Diesel HEV, in order to approximate the costs of the PHEV versions of these technologies. In general, Diesel ICEs, HEVs, and PHEVs are more expensive than the E-85 Flex Fuel versions, which are more expensive than the Gasoline versions. In calculating PHEV efficiencies, I assume that Gasoline, E-85 Flex Fuel, and Diesel PHEV 10/30/40/60 efficiencies in charge-sustaining (CS) mode are the same as for their HEV counterparts, while efficiencies in charge-depleting (CD) mode are much higher, due to the greater efficiency of an electric motor in all-electric operation.[39] CD-mode efficiencies are based on the technology characterizations of EPRI (2007) and Kromer and Heywood (2007a). Furthermore, PHEVs are restricted from over-consuming either

[39] Note that the assumption of all PHEVs having the same efficiency in charge-sustaining mode is a bit of an approximation because of the varying weights that these vehicles would achieve. However, for this same reason, I assume that PHEV efficiencies in charge-depleting mode are lower for vehicles with greater all-electric ranges (i.e., heavier battery packs).

electricity or liquid fuel for propulsion energy by applying fuel split shares based on published utility factor curves (EPRI, 2007; Kromer and Heywood, 2007a).

**Table 24 Investment Cost Assumptions for New Light-Duty Cars in the Reference Case**

**Investment Costs for New Light-Duty Cars ($/vehicle)**

*(Note: Missing data value indicates that technology is not available in given year.)*

| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gasoline ICE | 25,775 | 25,924 | 26,421 | 26,875 | 26,951 | 27,092 | 27,291 | 27,291 | 27,291 | 27,291 | 27,291 |
| Gasoline ICE (Moderate Eff.) | 26,531 | 26,681 | 27,178 | 27,631 | 27,708 | 27,849 | 28,047 | 28,047 | 28,047 | 28,047 | 28,047 |
| Gasoline ICE (Advanced Eff.) | 27,288 | 27,437 | 27,934 | 28,388 | 28,464 | 28,605 | 28,804 | 28,804 | 28,804 | 28,804 | 28,804 |
| Gasoline HEV | 29,473 | 29,413 | 29,491 | 29,557 | 29,427 | 29,358 | 29,437 | 29,437 | 29,437 | 29,437 | 29,437 |
| E85 Flex Fuel ICE | 26,150 | 26,299 | 26,797 | 27,251 | 27,326 | 27,465 | 27,661 | 27,661 | 27,661 | 27,661 | 27,661 |
| E85 Flex Fuel ICE (Moderate Eff.) | 26,906 | 27,055 | 27,554 | 28,008 | 28,082 | 28,221 | 28,417 | 28,417 | 28,417 | 28,417 | 28,417 |
| E85 Flex Fuel ICE (Advanced Eff.) | 27,663 | 27,812 | 28,310 | 28,764 | 28,839 | 28,977 | 29,174 | 29,174 | 29,174 | 29,174 | 29,174 |
| E85 Flex Fuel HEV | 29,848 | 29,787 | 29,866 | 29,934 | 29,801 | 29,730 | 29,806 | 29,806 | 29,806 | 29,806 | 29,806 |
| Diesel ICE | 31,220 | 31,352 | 30,528 | 30,155 | 29,868 | 29,923 | 29,955 | 29,955 | 29,955 | 29,955 | 29,955 |
| Diesel HEV | -- | -- | 29,788 | 29,788 | 29,637 | 29,549 | 29,582 | 29,582 | 29,582 | 29,582 | 29,582 |
| Gasoline PHEV10 | 31,967 | 31,967 | 31,967 | 31,456 | 30,962 | 30,745 | 30,824 | 30,824 | 30,824 | 30,824 | 30,824 |
| Gasoline PHEV30 | 40,800 | 40,800 | 40,800 | 38,228 | 36,439 | 35,693 | 35,772 | 35,772 | 35,772 | 35,772 | 35,772 |
| Gasoline PHEV40 | 45,216 | 45,216 | 45,216 | 41,614 | 39,178 | 38,167 | 38,246 | 38,246 | 38,246 | 38,246 | 38,246 |
| Gasoline PHEV60 | 54,049 | 54,049 | 54,049 | 48,386 | 44,655 | 43,115 | 43,194 | 43,194 | 43,194 | 43,194 | 43,194 |
| E85 Flex Fuel PHEV10 | 32,343 | 32,343 | 32,343 | 31,832 | 31,337 | 31,117 | 31,194 | 31,194 | 31,194 | 31,194 | 31,194 |
| E85 Flex Fuel PHEV30 | 41,176 | 41,176 | 41,176 | 38,604 | 36,814 | 36,065 | 36,142 | 36,142 | 36,142 | 36,142 | 36,142 |
| E85 Flex Fuel PHEV40 | 45,592 | 45,592 | 45,592 | 41,990 | 39,552 | 38,539 | 38,616 | 38,616 | 38,616 | 38,616 | 38,616 |
| E85 Flex Fuel PHEV60 | 54,425 | 54,425 | 54,425 | 48,762 | 45,029 | 43,487 | 43,564 | 43,564 | 43,564 | 43,564 | 43,564 |
| Diesel PHEV10 | 31,686 | 31,686 | 31,686 | 31,686 | 31,172 | 30,936 | 30,969 | 30,969 | 30,969 | 30,969 | 30,969 |
| Diesel PHEV30 | 38,458 | 38,458 | 38,458 | 38,458 | 36,649 | 35,884 | 35,917 | 35,917 | 35,917 | 35,917 | 35,917 |
| Diesel PHEV40 | 41,844 | 41,844 | 41,844 | 41,844 | 39,388 | 38,358 | 38,391 | 38,391 | 38,391 | 38,391 | 38,391 |
| Diesel PHEV60 | 48,616 | 48,616 | 48,616 | 48,616 | 44,865 | 43,306 | 43,339 | 43,339 | 43,339 | 43,339 | 43,339 |
| Battery-Electric | 89,485 | 93,325 | 95,286 | 95,123 | 85,823 | 78,071 | 77,915 | 77,915 | 77,915 | 77,915 | 77,915 |
| Hydrogen Fuel Cell | -- | -- | 73,508 | 64,341 | 57,823 | 52,850 | 49,037 | 49,037 | 49,037 | 49,037 | 49,037 |
| Gasoline Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Methanol Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Dedicated Ethanol ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Natural Gas ICE | 33,400 | 33,541 | 33,971 | 34,413 | 34,485 | 34,607 | 34,790 | 34,790 | 34,790 | 34,790 | 34,790 |
| Natural Gas Bi-Fuel ICE | 32,065 | 32,211 | 32,634 | 33,077 | 33,159 | 33,300 | 33,515 | 33,515 | 33,515 | 33,515 | 33,515 |
| LPG ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| LPG Bi-Fuel ICE | 31,104 | 31,253 | 31,750 | 32,204 | 32,280 | 32,421 | 32,620 | 32,620 | 32,620 | 32,620 | 32,620 |

**Table 25 Investment Cost Assumptions for New Light-Duty Trucks in the Reference Case**

**Investment Costs for New Light-Duty Trucks ($/vehicle)**

*(Note: Missing data value indicates that technology is not available in given year.)*

| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gasoline ICE | 34,084 | 34,207 | 34,658 | 35,174 | 35,353 | 35,561 | 35,818 | 35,818 | 35,818 | 35,818 | 35,818 |
| Gasoline ICE (Moderate Eff.) | 35,263 | 35,386 | 35,837 | 36,353 | 36,532 | 36,740 | 36,997 | 36,997 | 36,997 | 36,997 | 36,997 |
| Gasoline ICE (Advanced Eff.) | 36,442 | 36,565 | 37,016 | 37,532 | 37,711 | 37,919 | 38,176 | 38,176 | 38,176 | 38,176 | 38,176 |
| Gasoline HEV | 38,465 | 38,401 | 38,376 | 38,388 | 38,258 | 38,236 | 38,394 | 38,394 | 38,394 | 38,394 | 38,394 |
| E85 Flex Fuel ICE | 34,535 | 34,657 | 35,106 | 35,620 | 35,796 | 36,001 | 36,257 | 36,257 | 36,257 | 36,257 | 36,257 |
| E85 Flex Fuel ICE (Moderate Eff.) | 35,714 | 35,836 | 36,285 | 36,799 | 36,975 | 37,180 | 37,436 | 37,436 | 37,436 | 37,436 | 37,436 |
| E85 Flex Fuel ICE (Advanced Eff.) | 36,893 | 37,015 | 37,464 | 37,978 | 38,154 | 38,359 | 38,615 | 38,615 | 38,615 | 38,615 | 38,615 |
| E85 Flex Fuel HEV | 38,915 | 38,851 | 38,824 | 38,835 | 38,700 | 38,677 | 38,833 | 38,833 | 38,833 | 38,833 | 38,833 |
| Diesel ICE | 42,334 | 42,441 | 40,425 | 40,491 | 40,175 | 40,114 | 40,387 | 40,387 | 40,387 | 40,387 | 40,387 |
| Diesel HEV | -- | -- | -- | 38,413 | 38,238 | 38,181 | 38,277 | 38,277 | 38,277 | 38,277 | 38,277 |
| Gasoline PHEV10 | 39,793 | 39,793 | 39,793 | 39,793 | 39,793 | 39,623 | 39,781 | 39,781 | 39,781 | 39,781 | 39,781 |
| Gasoline PHEV30 | 45,270 | 45,270 | 45,270 | 45,270 | 45,270 | 44,571 | 44,729 | 44,729 | 44,729 | 44,729 | 44,729 |
| Gasoline PHEV40 | 48,008 | 48,008 | 48,008 | 48,008 | 48,008 | 47,045 | 47,203 | 47,203 | 47,203 | 47,203 | 47,203 |
| Gasoline PHEV60 | 53,485 | 53,485 | 53,485 | 53,485 | 53,485 | 51,993 | 52,151 | 52,151 | 52,151 | 52,151 | 52,151 |
| E85 Flex Fuel PHEV10 | 40,236 | 40,236 | 40,236 | 40,236 | 40,236 | 40,064 | 40,220 | 40,220 | 40,220 | 40,220 | 40,220 |
| E85 Flex Fuel PHEV30 | 45,713 | 45,713 | 45,713 | 45,713 | 45,713 | 45,012 | 45,168 | 45,168 | 45,168 | 45,168 | 45,168 |
| E85 Flex Fuel PHEV40 | 48,451 | 48,451 | 48,451 | 48,451 | 48,451 | 47,486 | 47,642 | 47,642 | 47,642 | 47,642 | 47,642 |
| E85 Flex Fuel PHEV60 | 53,928 | 53,928 | 53,928 | 53,928 | 53,928 | 52,434 | 52,590 | 52,590 | 52,590 | 52,590 | 52,590 |
| Diesel PHEV10 | 39,773 | 39,773 | 39,773 | 39,773 | 39,773 | 39,568 | 39,664 | 39,664 | 39,664 | 39,664 | 39,664 |
| Diesel PHEV30 | 45,250 | 45,250 | 45,250 | 45,250 | 45,250 | 44,516 | 44,612 | 44,612 | 44,612 | 44,612 | 44,612 |
| Diesel PHEV40 | 47,989 | 47,989 | 47,989 | 47,989 | 47,989 | 46,990 | 47,086 | 47,086 | 47,086 | 47,086 | 47,086 |
| Diesel PHEV60 | 53,466 | 53,466 | 53,466 | 53,466 | 53,466 | 51,938 | 52,034 | 52,034 | 52,034 | 52,034 | 52,034 |
| Battery-Electric | 111,741 | 115,151 | 115,090 | 115,319 | 104,277 | 95,115 | 95,166 | 95,166 | 95,166 | 95,166 | 95,166 |
| Hydrogen Fuel Cell | -- | -- | 80,120 | 69,446 | 61,602 | 55,599 | 50,942 | 50,942 | 50,942 | 50,942 | 50,942 |
| Gasoline Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Methanol Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Dedicated Ethanol ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Natural Gas ICE | 33,503 | 33,584 | 34,026 | 34,630 | 34,749 | 34,898 | 35,064 | 35,064 | 35,064 | 35,064 | 35,064 |
| Natural Gas Bi-Fuel ICE | 32,604 | 32,687 | 33,123 | 33,716 | 33,837 | 33,991 | 34,173 | 34,173 | 34,173 | 34,173 | 34,173 |
| LPG ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| LPG Bi-Fuel ICE | 31,269 | 31,361 | 31,839 | 32,532 | 32,676 | 32,834 | 33,013 | 33,013 | 33,013 | 33,013 | 33,013 |

**Table 26 Fuel Economy Assumptions for New Light-Duty Cars, All Except PHEVs in the Reference Case**

**New Vehicle Fuel Economy (mpgge) - All Except PHEVs**

*(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)*

| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gasoline ICE | 31.2 | 31.5 | 34.3 | 37.1 | 37.8 | 38.6 | 40.0 | 40.0 | 40.0 | 40.0 | 40.0 |
| Gasoline ICE (Moderate Eff.) | 35.3 | 35.7 | 38.8 | 42.0 | 42.7 | 43.6 | 45.2 | 45.2 | 45.2 | 45.2 | 45.2 |
| Gasoline ICE (Advanced Eff.) | 40.6 | 41.0 | 44.6 | 48.3 | 49.1 | 50.1 | 52.0 | 52.0 | 52.0 | 52.0 | 52.0 |
| Gasoline HEV | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| E85 Flex Fuel ICE | 31.5 | 31.9 | 34.6 | 37.5 | 38.1 | 38.9 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| E85 Flex Fuel ICE (Moderate Eff.) | 35.3 | 35.7 | 38.8 | 42.0 | 42.7 | 43.6 | 45.2 | 45.2 | 45.2 | 45.2 | 45.2 |
| E85 Flex Fuel ICE (Advanced Eff.) | 40.6 | 41.0 | 44.6 | 48.3 | 49.1 | 50.1 | 52.0 | 52.0 | 52.0 | 52.0 | 52.0 |
| E85 Flex Fuel HEV | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| Diesel ICE | 39.2 | 39.5 | 42.4 | 45.6 | 46.2 | 46.7 | 47.0 | 47.0 | 47.0 | 47.0 | 47.0 |
| Diesel HEV | -- | -- | 59.5 | 59.1 | 59.8 | 60.3 | 60.6 | 60.6 | 60.6 | 60.6 | 60.6 |
| Battery-Electric | 91.1 | 86.8 | 100.9 | 126.0 | 149.3 | 148.4 | 146.5 | 146.5 | 146.5 | 146.5 | 146.5 |
| Hydrogen Fuel Cell | 74.9 | 75.7 | 82.3 | 89.1 | 90.6 | 92.5 | 96.0 | 96.0 | 96.0 | 96.0 | 96.0 |
| Gasoline Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Methanol Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Dedicated Ethanol ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Natural Gas ICE | 33.2 | 33.4 | 36.6 | 39.5 | 40.2 | 41.0 | 41.9 | 41.9 | 41.9 | 41.9 | 41.9 |
| Natural Gas Bi-Fuel ICE | 30.8 | 31.0 | 33.9 | 36.6 | 37.2 | 38.0 | 39.0 | 39.0 | 39.0 | 39.0 | 39.0 |
| LPG ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| LPG Bi-Fuel ICE | 31.2 | 31.5 | 34.3 | 37.1 | 37.7 | 38.6 | 40.0 | 40.0 | 40.0 | 40.0 | 40.0 |

**Table 27 Fuel Economy Assumptions for New Light-Duty PHEV Cars in the Reference Case**

| New Plug-in Hybrid Vehicle Fuel Economy (mpgge) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)* | | | | | | | | | | | |
| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
| **Charge-Sustaining Mode** | | | | | | | | | | | |
| **Gasoline PHEV10** | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| **Gasoline PHEV30** | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| **Gasoline PHEV40** | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| **Gasoline PHEV60** | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| **E85 Flex Fuel PHEV10** | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| **E85 Flex Fuel PHEV30** | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| **E85 Flex Fuel PHEV40** | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| **E85 Flex Fuel PHEV60** | 45.1 | 44.9 | 48.5 | 51.0 | 51.8 | 52.6 | 53.5 | 53.5 | 53.5 | 53.5 | 53.5 |
| **Diesel PHEV10** | -- | -- | 59.5 | 59.1 | 59.8 | 60.3 | 60.6 | 60.6 | 60.6 | 60.6 | 60.6 |
| **Diesel PHEV30** | -- | -- | 59.5 | 59.1 | 59.8 | 60.3 | 60.6 | 60.6 | 60.6 | 60.6 | 60.6 |
| **Diesel PHEV40** | -- | -- | 59.5 | 59.1 | 59.8 | 60.3 | 60.6 | 60.6 | 60.6 | 60.6 | 60.6 |
| **Diesel PHEV60** | -- | -- | 59.5 | 59.1 | 59.8 | 60.3 | 60.6 | 60.6 | 60.6 | 60.6 | 60.6 |
| **Charge-Depleting Mode** | | | | | | | | | | | |
| **Gasoline PHEV10** | 158.7 | 158.2 | 157.2 | 175.0 | 197.6 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 |
| **Gasoline PHEV30** | 156.9 | 156.3 | 155.4 | 170.5 | 189.2 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 |
| **Gasoline PHEV40** | 156.9 | 156.3 | 155.4 | 170.5 | 189.2 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 |
| **Gasoline PHEV60** | 155.3 | 154.8 | 153.8 | 166.8 | 182.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 |
| **E85 Flex Fuel PHEV10** | 158.7 | 158.2 | 157.2 | 175.0 | 197.6 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 |
| **E85 Flex Fuel PHEV30** | 156.9 | 156.3 | 155.4 | 170.5 | 189.2 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 |
| **E85 Flex Fuel PHEV40** | 156.9 | 156.3 | 155.4 | 170.5 | 189.2 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 |
| **E85 Flex Fuel PHEV60** | 155.3 | 154.8 | 153.8 | 166.8 | 182.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 |
| **Diesel PHEV10** | -- | -- | 157.2 | 175.0 | 197.6 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 |
| **Diesel PHEV30** | -- | -- | 155.4 | 170.5 | 189.2 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 |
| **Diesel PHEV40** | -- | -- | 155.4 | 170.5 | 189.2 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 |
| **Diesel PHEV60** | -- | -- | 153.8 | 166.8 | 182.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 |

**Table 28 Fuel Economy Assumptions for New Light-Duty Trucks, All Except PHEVs in the Reference Case**

| New Vehicle Fuel Economy (mpgge) - All Except PHEVs | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)* | | | | | | | | | | | |
| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
| **Gasoline ICE** | 22.5 | 22.5 | 24.4 | 26.9 | 28.0 | 28.9 | 30.0 | 30.0 | 30.0 | 30.0 | 30.0 |
| **Gasoline ICE (Moderate Eff.)** | 26.0 | 26.0 | 28.2 | 31.1 | 32.4 | 33.4 | 34.7 | 34.7 | 34.7 | 34.7 | 34.7 |
| **Gasoline ICE (Advanced Eff.)** | 30.8 | 30.7 | 33.3 | 36.8 | 38.3 | 39.5 | 41.0 | 41.0 | 41.0 | 41.0 | 41.0 |
| **Gasoline HEV** | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| **E85 Flex Fuel ICE** | 22.8 | 22.7 | 24.6 | 27.2 | 28.3 | 29.2 | 30.3 | 30.3 | 30.3 | 30.3 | 30.3 |
| **E85 Flex Fuel ICE (Moderate Eff.)** | 26.0 | 26.0 | 28.2 | 31.1 | 32.4 | 33.4 | 34.7 | 34.7 | 34.7 | 34.7 | 34.7 |
| **E85 Flex Fuel ICE (Advanced Eff.)** | 30.8 | 30.7 | 33.3 | 36.8 | 38.3 | 39.5 | 41.0 | 41.0 | 41.0 | 41.0 | 41.0 |
| **E85 Flex Fuel HEV** | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| **Diesel ICE** | 28.4 | 28.2 | 30.1 | 32.5 | 33.4 | 34.1 | 34.6 | 34.6 | 34.6 | 34.6 | 34.6 |
| **Diesel HEV** | 41.2 | 41.2 | 41.2 | 41.2 | 42.1 | 42.8 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Battery-Electric** | 51.7 | 53.4 | 63.4 | 78.4 | 92.7 | 92.4 | 92.1 | 92.1 | 92.1 | 92.1 | 92.1 |
| **Hydrogen Fuel Cell** | 54.1 | 54.1 | 58.6 | 64.6 | 67.3 | 69.4 | 72.1 | 72.1 | 72.1 | 72.1 | 72.1 |
| **Gasoline Fuel Cell** | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| **Methanol Fuel Cell** | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| **Dedicated Ethanol ICE** | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| **Natural Gas ICE** | 25.7 | 25.6 | 27.8 | 30.9 | 31.8 | 32.6 | 33.5 | 33.5 | 33.5 | 33.5 | 33.5 |
| **Natural Gas Bi-Fuel ICE** | 23.9 | 23.7 | 25.7 | 28.6 | 29.4 | 30.2 | 31.1 | 31.1 | 31.1 | 31.1 | 31.1 |
| **LPG ICE** | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| **LPG Bi-Fuel ICE** | 23.9 | 23.8 | 26.0 | 29.5 | 30.6 | 31.4 | 32.4 | 32.4 | 32.4 | 32.4 | 32.4 |

**Table 29 Fuel Economy Assumptions for New Light-Duty PHEV Trucks in the Reference Case**

**New Plug-in Hybrid Vehicle Fuel Economy (mpgge)**

*(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)*

| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Charge-Sustaining Mode** | | | | | | | | | | | |
| Gasoline PHEV10 | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| Gasoline PHEV30 | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| Gasoline PHEV40 | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| Gasoline PHEV60 | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| E85 Flex Fuel PHEV10 | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| E85 Flex Fuel PHEV30 | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| E85 Flex Fuel PHEV40 | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| E85 Flex Fuel PHEV60 | 32.6 | 32.4 | 35.1 | 37.6 | 38.6 | 39.5 | 40.3 | 40.3 | 40.3 | 40.3 | 40.3 |
| Diesel PHEV10 | 41.2 | 41.2 | 41.2 | 41.2 | 42.1 | 42.8 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| Diesel PHEV30 | 41.2 | 41.2 | 41.2 | 41.2 | 42.1 | 42.8 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| Diesel PHEV40 | 41.2 | 41.2 | 41.2 | 41.2 | 42.1 | 42.8 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| Diesel PHEV60 | 41.2 | 41.2 | 41.2 | 41.2 | 42.1 | 42.8 | 43.3 | 43.3 | 43.3 | 43.3 | 43.3 |
| **Charge-Depleting Mode** | | | | | | | | | | | |
| Gasoline PHEV10 | 158.1 | 158.1 | 158.1 | 158.1 | 158.1 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 |
| Gasoline PHEV30 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 |
| Gasoline PHEV40 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 |
| Gasoline PHEV60 | 145.9 | 145.9 | 145.9 | 145.9 | 145.9 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 |
| E85 Flex Fuel PHEV10 | 158.1 | 158.1 | 158.1 | 158.1 | 158.1 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 |
| E85 Flex Fuel PHEV30 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 |
| E85 Flex Fuel PHEV40 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 |
| E85 Flex Fuel PHEV60 | 145.9 | 145.9 | 145.9 | 145.9 | 145.9 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 |
| Diesel PHEV10 | 158.1 | 158.1 | 158.1 | 158.1 | 158.1 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 |
| Diesel PHEV30 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 |
| Diesel PHEV40 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 |
| Diesel PHEV60 | 145.9 | 145.9 | 145.9 | 145.9 | 145.9 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 |

## II.3 Scenario Results and Discussion

Now that the structure of the CA-TIMES model and many of its assumptions have been described, this section highlights the results of several analyses in which the model was used to understand how the California energy system could be significantly decarbonized in the long term, what the technological and resource implications might be in such a case, and how much the energy system transition could cost. To this end, a number of scenarios have been created using the model, first a Reference Case scenario and then a multi-strategy Deep GHG Reduction Scenario that looks specifically at an ambitious "80in50" emission reduction target for the entire energy system (not just the transport sector, as was the case in the original 80in50 studies described in the Chapter I of this dissertation). Finally, several variants of the Deep GHG Reduction Scenario are analyzed, in order to understand how the transition to a low-carbon economy in California could be different if the potential of certain technologies and resources is substantially restricted or enhanced.

### *II.3.1 Reference Case Scenario*

The CA-TIMES Reference Case is a scenario describing the potential development of California's energy system over the next several decades under business-as-usual (BAU) conditions. It is not a prediction of what will happen, but rather a single vision of what *could* happen, if the technological and policy assumptions in the model were to come to fruition and consumers and firms behaved optimally from a cost minimization standpoint. While, in theory, a number of Reference Case scenarios could be developed, it is really only practical to develop one. The Reference Case is the scenario to which all other scenarios, particularly the deep greenhouse gas reduction scenarios, are compared. The following sections illustrate the development of the energy system in the Reference Case, taking an in-depth view of it from a variety of different perspectives. These various "cuts" hopefully provide a sense for how the system could potentially develop in the absence of any substantial effort to transition California toward a low-carbon society.

Policy is an important driver of energy system development. And while the previous sections have discussed the most important resource, technology, and demand assumptions – and their respective data sources – that have been used to develop the CA-TIMES Reference Case, the Reference Case is also strongly dependent on current policies and how they are assumed to develop over time.

Table 30 summarizes the policies represented in the Reference Case, providing brief descriptions of each, how they are modeled in CA-TIMES, and when they are assumed to expire, if at all. Although it is not possible to represent every single policy that affects California's energy system, the list below attempts to capture those of greatest importance and with the largest impact. Notably excluded from explicit policy representation are, for example, the Low Carbon Fuel Standard (LCFS), Zero Emissions Vehicle (ZEV) mandates, California's "anti-sprawl" transportation and land use regulations (SB 375), and certain measures for appliance energy efficiency and goods movement. Future iterations will make it possible to represent these policies, especially with respect to the LCFS, for which the emissions accounting framework of CA-TIMES would first need to be significantly overhauled.

**Table 30 Brief Descriptions of Policies Represented in the CA-TIMES Reference Case**

| Policies | Descriptions |
|---|---|
| Biofuel Subsidies | - Corn ethanol: Federal Volumetric Ethanol Excise Tax Credit (i.e., "blender's credit") of \$0.45/gal. Assumed to expire in 2015.<br>- Sugar cane ethanol: Same as corn ethanol.<br>- Cellulosic ethanol: Federal tax credit of \$1.01/gal. Based on the Food, Conservation and Energy Act of 2008 (i.e., the "farm bill"). Assumed to expire in 2020.<br>- Biodiesel: Federal tax credit of \$1.00/gal for biodiesel from soy and animal tallow, \$0.50/gal for biodiesel from yellow grease. Based on American Jobs Creation Act of 2004. Assumed to expire in 2015. |
| Biofuel Import Tariffs | - Sugar cane and other types of imported ethanol: Import duty of \$0.54/gal. |
| Transportation Fuel Taxes[40] | - Gasoline: California state tax of \$0.49/gal (includes excise tax and state, county, and local sales taxes). Federal excise tax of \$0.184/gal. Assumed to always be the same.<br>- Diesel: California state tax of \$0.49/gal (includes excise tax and state, county, and local sales taxes). Federal excise tax of \$0.244/gal. Assumed to always be the same.<br>- Ethanol and E-85: No additional taxes other than those for gasoline.<br>- Jet Fuel (kerosene-type): Federal excise tax of \$0.044/gal for commercial aviation.<br>- Aviation gasoline: Federal excise tax of \$0.194/gal. Assumed to always be the same.<br>- Liquid Petroleum Gases (LPG): Federal excise tax of \$0.183/gal. Assumed to always be the same.<br>- Compressed Natural Gas (CNG): Federal excise tax of \$0.044/gal. Assumed to be the same as jet fuel. Assumed to always be the same.<br>- Liquefied Natural Gas (LNG): Federal excise tax of \$0.243/gal. Assumed to always be the same.<br>- Liquefied $H_2$: Federal excise tax of \$0.184/gal. Assumed to be the same as conventional gasoline. Assumed to always be the same.<br>- FT liquid fuels from coal: Federal excise tax of \$0.244/gal. Assumed to be the same as conventional diesel. Assumed to always be the same.<br>- FT liquid fuels from biomass: Federal excise tax of \$0.244/gal. Assumed to be the same as conventional diesel. Assumed to always be the same. |
| Corporate Average Fuel Economy (CAFE) Standards | - Light-duty passenger cars: New model-year vehicle fleet must achieve 263 $gCO_2$/mile (33.8 mpg) in 2012, strengthening to 225 $gCO_2$/mile (39.5 mpg) in 2016, assumed to remain constant thereafter.<br>- Light-duty passenger trucks: New model-year vehicle fleet must achieve 346 $gCO_2$/mile (25.7 mpg) in 2012, strengthening to 298 $gCO_2$/mile (29.8 mpg) in 2016, assumed to remain constant thereafter. |
| Electric Vehicle Subsidies | - Light-duty PHEVs and BEVs: Tax credit for new plug-in electric vehicles is worth \$2,500 plus \$417 for each kWh of battery capacity over 5 kWh. The portion of the credit determined by battery capacity cannot exceed \$5,000; therefore, the total amount of the credit allowed for a new plug-in electric vehicle is \$7,500. Based on the Energy Improvement and Extension Act of 2008, and later the American Clean Energy and Security Act of 2009. Credit is supposed to expire for each manufacturer soon after it has sold 200,000 cumulative PHEV/BEVs for use in the U.S. However, in CA-TIMES the credit is simply assumed to expire in 2012. |
| GHG Emission Performance Standard for New Power Plants | - Establishes a greenhouse gases emission performance standard for all baseload generation of local publicly owned electric utilities at a rate of emissions of greenhouse gases that is no higher than the rate of emissions of greenhouse gases for combined-cycle natural gas baseload generation [California Senate Bill (SB) 1368]. This essentially equates to "no new coal plants in California". In CA-TIMES, the law is applied to coal steam, coal IGCC, and coal-to-$H_2$ |

[40] For current federal fuel tax information, see the following U.S. Internal Revenue Service (IRS) webpage: http://www.irs.gov/publications/p510/ch01.html#d0e2009. For current state gasoline and diesel tax information, see the following API webpage: http://www.api.org/statistics/fueltaxes/.

| | |
|---|---|
| | plants. |
| Renewable Fuels Standard (RFS) | - Mandates the increased use of transportation biofuels, culminating in 15 billion gallons per year (BGY) of corn ethanol in 2022, 16 BGY cellulosic ethanol, 1 BGY biodiesel, and 4 BGY other advanced biofuels. "Other advanced biofuels" are assumed to be sugar cane ethanol and bio-gasoline in the CA-TIMES model. RFS mandates are assumed to end in 2022. California is assumed to only be "responsible" for 9% to 10.5% of the total U.S. biofuels mandates, consistent with its current and projected share of the U.S. population and liquid fuels consumption. Based on the Energy Independence and Security Act (EISA) of 2007. |
| Renewable Electricity Incentives | - Renewable electricity production tax credit (PTC): Credit of 2.2 cents/kWh for Wind, Geothermal, and Closed-loop biomass; and 1.1 cents/kWh for all other renewables (Open-loop biomass, Landfill gas, Hydroelectric, Municipal Solid Waste, Hydrokinetic "Flowing Water" Power, Small Hydroelectric, Tidal Energy, Wave Energy, and Ocean Thermal). Duration of credit is 10 years for facilities placed in service by the end of 2012 (wind) or 2013 (all others). Thus, all credits assumed to expire by 2022/2023. Note that Solar is excluded from the production tax credit because it receives the investment tax credit.<br>- Business energy investment tax credit (ITC) for renewables: Credit equal to 30% of capital expenditures for Solar and Fuel cells. No maximum credit for solar; a maximum of $3,000/kW for fuel cells. In general, credits are available for eligible systems placed in service before the end of 2016. In CA-TIMES, credits are assumed to expire in 2016. Note that as of 2009, other types of renewable generation are allowed to take the ITC; however, they would then have to forfeit the PTC. In CA-TIMES, it is assumed that only solar and fuel cells can take the ITC. |

*Electricity Generation*

The electric generation sector is sure to play an instrumental role in the future development of California's energy system and its corresponding environmental impacts. Figure 28 illustrates the model's Reference Case projections for electricity generation by plant type over the entire time horizon. Several noteworthy observations can be made. First, electricity supply and demand is projected to grow significantly over the next several decades (by more than 50%). This will necessitate considerable future investment in the generation stock, especially in light of the multitude of older, existing plants, which are scheduled to retire over the next two decades. Second, natural gas generation grows considerably between 2020 and 2025. This is due to natural gas being the most attractive, least-cost generation source during these years and because a significant amount of generation is needed after 2020 to make up for the shortfall caused by the retirement of existing nuclear plants and termination of existing electricity import contracts, both of which are scheduled to occur around 2020 or soon thereafter. The growth in natural gas generation is accounted for by the increased utilization of existing NGCC plants, many of which are not at the moment used to their full capacities, as well as investment in new NGCC plants. In short, natural gas becomes increasingly used for baseload power generation in California. Later in the model time horizon, generation from wind, geothermal, and solar thermal plants becomes cost-competitive with natural gas plants, thanks to increasing natural gas prices and assumed declines in the investment costs of these renewable options. This causes the share of low- and zero-carbon electricity generation to rise in the later periods, after having been relatively low for several decades as a result of the retirement of the state's two nuclear plants around 2020 (Figure 29). Unless the lives of existing nuclear plants are extended, new nuclear plants are built, and/or a renewable portfolio standard is implemented, fossil generation could still be quite high in California for years to come.

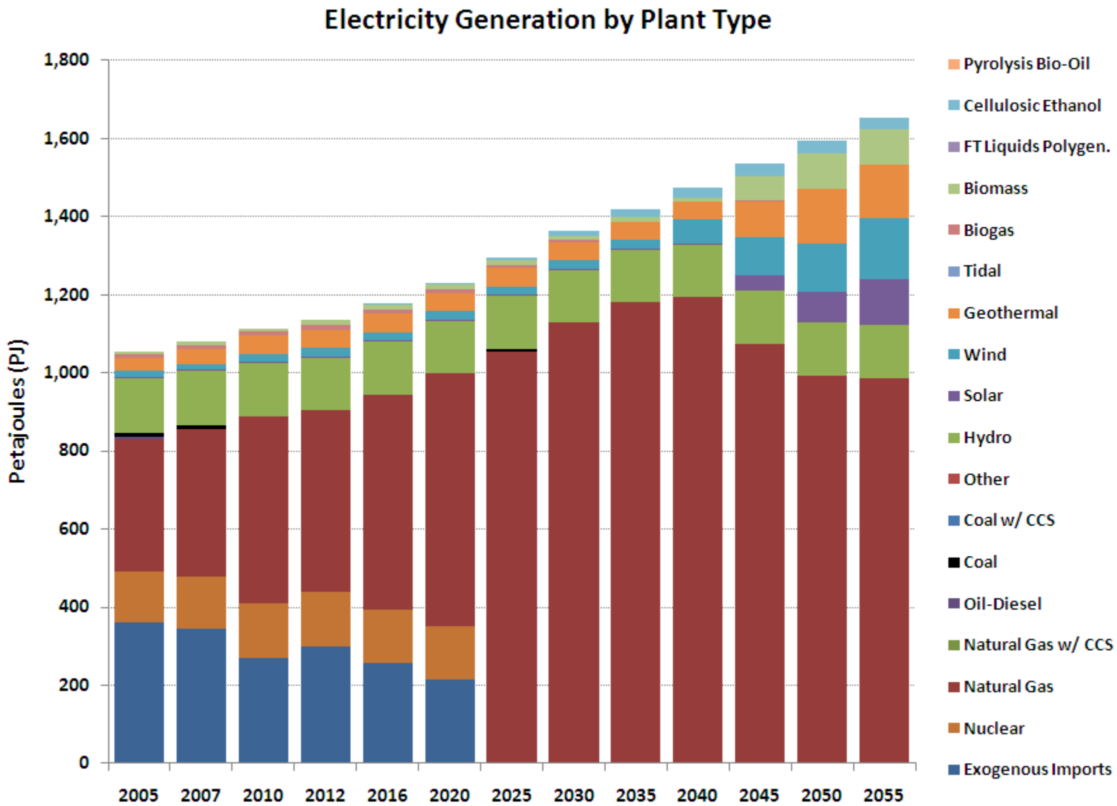


**Figure 28  Electricity Generation by Plant Type in the Reference Case**

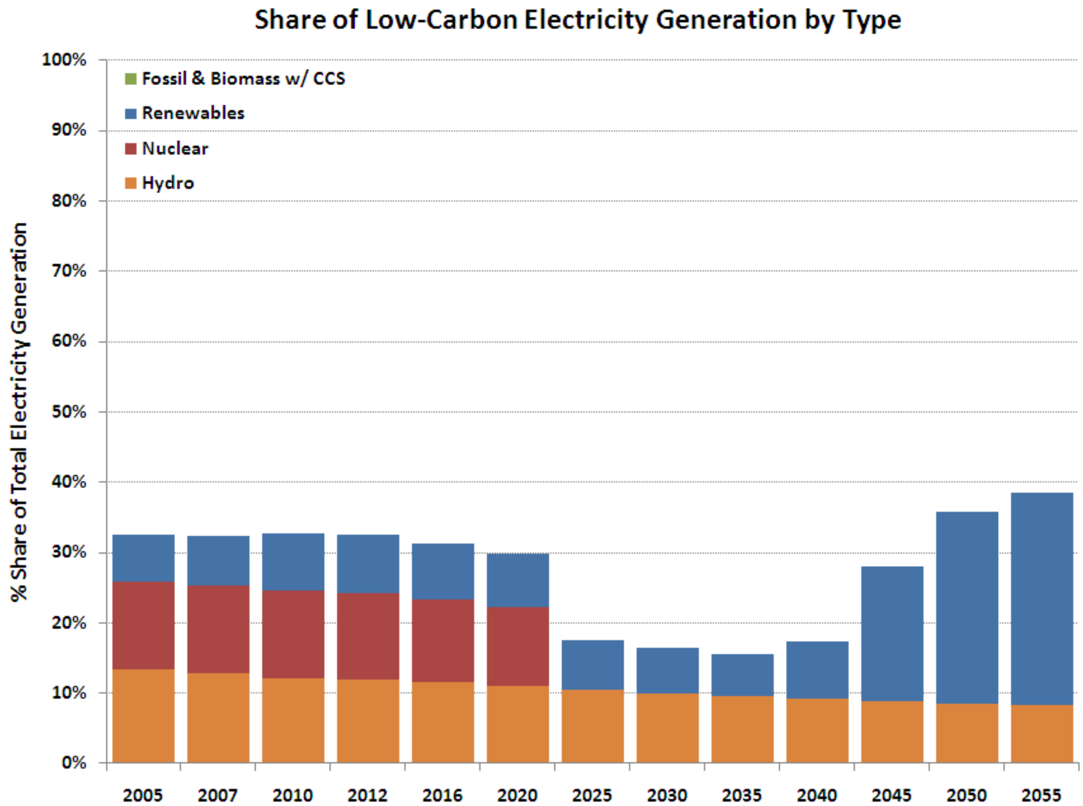


**Figure 29 Share of Low-Carbon Electricity Generation by Type in the Reference Case**

At this point, it is important to briefly note the way electricity imports are handled in CA-TIMES. There are two categories of imports, firm and system. Firm imports of coal, nuclear, hydro, and oil are dealt with in a relatively straightforward manner: they are phased out according to the scheduled expiration of known firm import contracts. System imports, on the other hand, are a bit less certain since they depend on the spot market for electricity, as well as electricity demand in other western states. In the CA-TIMES Reference Case, an important assumption is made that system imports from both the Pacific Northwest and Desert Southwest decline from 2010 to 2025, ultimately ceasing in this final year. This is not to say, however, that no electricity imports are allowed to enter California in the later years. They are just represented in a different way from the “Exogenous Imports” category shown in the figure (i.e., exogenous imports refers to current firm and system imports with a certain point-estimate cost signature, say in ¢/kWh, whose contracts are either set to retire within the next decade or whose use in California is difficult to predict going forward). From a modeling standpoint, it is preferable to represent all new electricity supply to California at the technology level (i.e., with investment cost, efficiency, availability data), rather than as commodity flows; hence, future supplies of imports are endogenously embedded in some of the power plant technologies listed in Table 7 and shown in Figure 28. For instance, although not shown, a portion of the wind generation expected in California in the Reference Case actually comes from out-of-state resources, since these resources are likely to be exploited by California electric utilities or their partners and are, thus, part of the California energy system within the framework of the CA-TIMES model. Similarly, due to siting issues, it may be reasonable to assume that a few of the natural gas plants that are brought into the state’s energy system over time will in fact be built outside of the its borders. The advantage of this approach to representing imports is that the electricity produced by these out-of-state power plants can be modeled with bottom-up technological detail. Note that electricity imports are also subject to the Renewable Portfolio Standard within the framework of CA-TIMES.

*Industrial, Commercial, Residential, and Agricultural Sectors*

Along with natural gas, electricity is one of the two most consumed energy commodities in the industrial, commercial, residential, and agricultural (ICRA) end-use sectors. Hence, it should not be surprising that the continuously growing energy demands of the

ICRA sectors are largely responsible for driving the increases in electricity generation witnessed above. Projections of useful energy demand by fuel type are shown for each of the ICRA sectors, starting in Figure 30. The industrial and commercial sectors appear poised for the most substantial growth over the next four decades, though growth is strong in the residential and agricultural sectors as well. In terms of the fuel mix, there is a small, but noticeable, shift from natural gas to electricity; yet, for the most part the mix remains unchanged. It is important to remember that, as discussed previously, both demand trajectories and the fuel use mix for each of the ICRA sectors are exogenously specified by the modeler for all future years. Therefore, the assumptions input to the model entirely govern the solution that is obtained. In developing the CA-TIMES Reference Case, I have decided to ground these exogenous assumptions in a publicly available scenario that has already undergone review, namely the *Baseline demand* scenario developed for the California Energy Commission as part of the UC-Davis Advanced Energy Pathways (AEP) project (McCarthy et al., 2008a, b). The energy demand projections created in the AEP study are based on growth trajectories for various other things, such as shipments of industrial and agricultural products, commercial floor space, number of residential households, gross state product, and population, to name just a few. Incremental energy efficiency improvements are taken into account in these projections, in the sense that the *Baseline demand* scenario assumes a continuation of historical and projected near-term trends – in other words, business-as-usual.

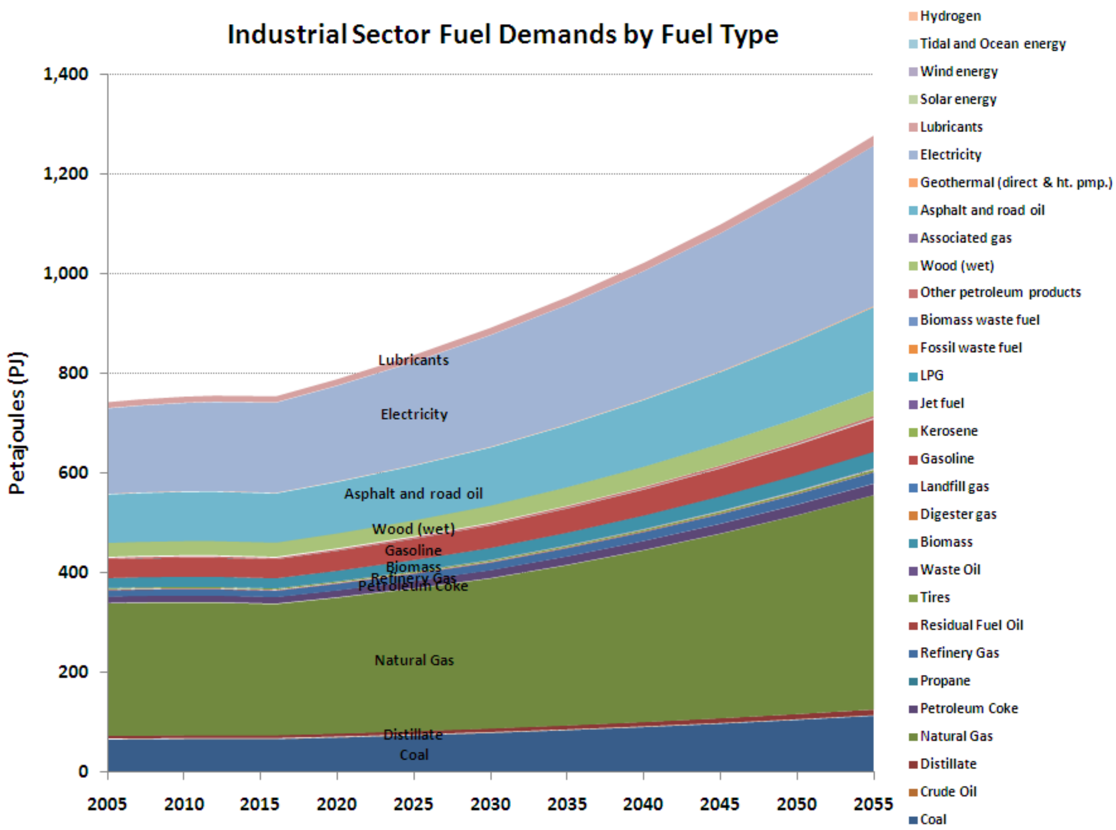


**Figure 30 Useful Energy Demand by Fuel Type in the Industrial Sector in the Reference Case**

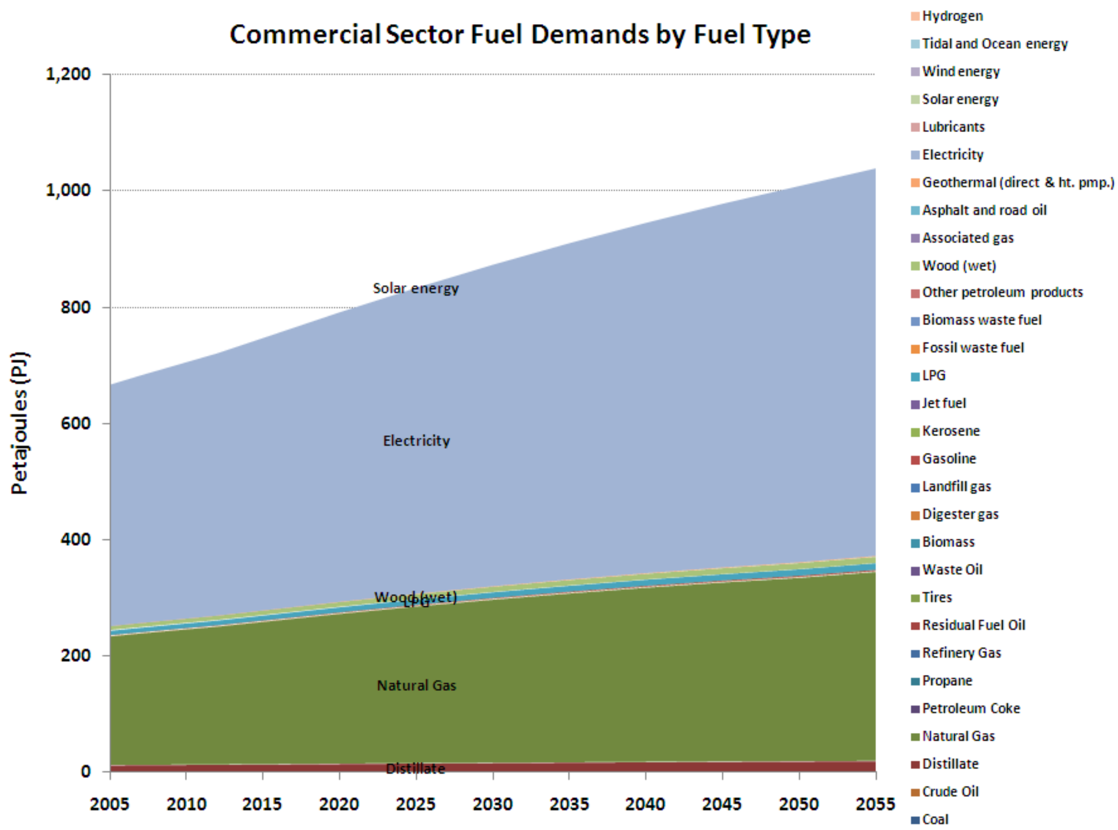


**Figure 31 Useful Energy Demand by Fuel Type in the Commercial Sector in the Reference Case**

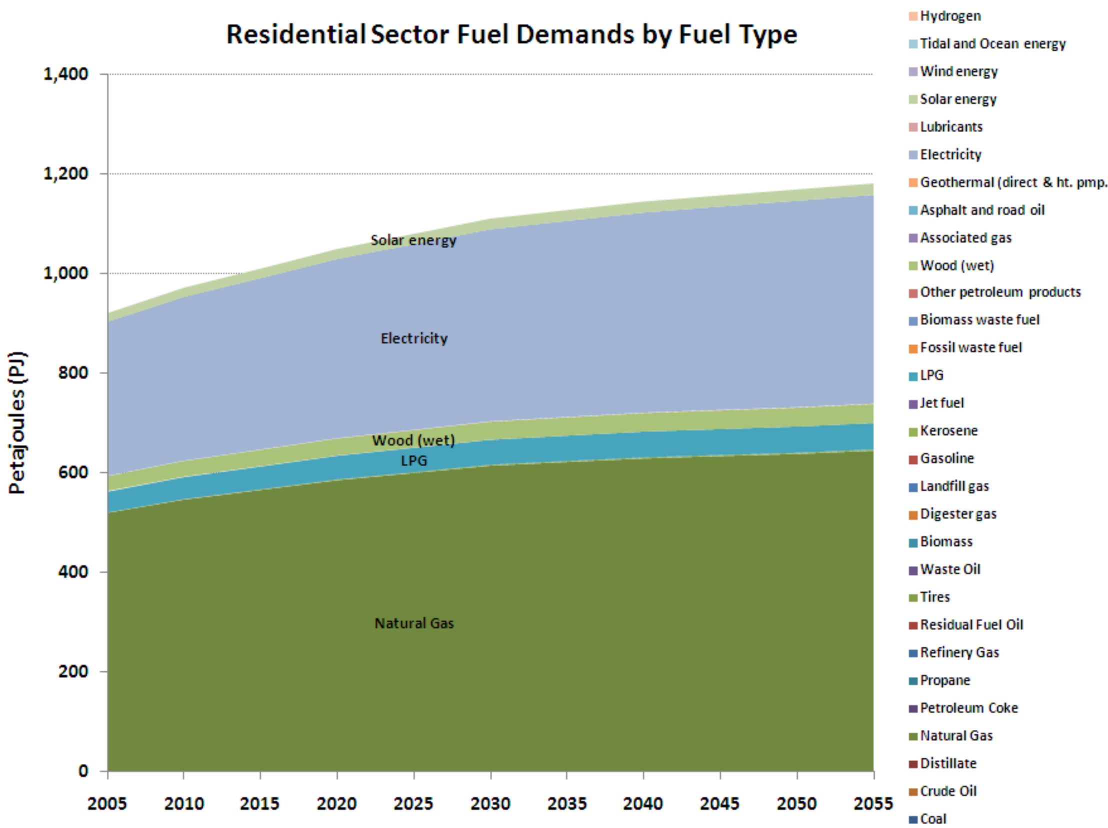


**Figure 32  Useful Energy Demand by Fuel Type in the Residential Sector in the Reference Case**

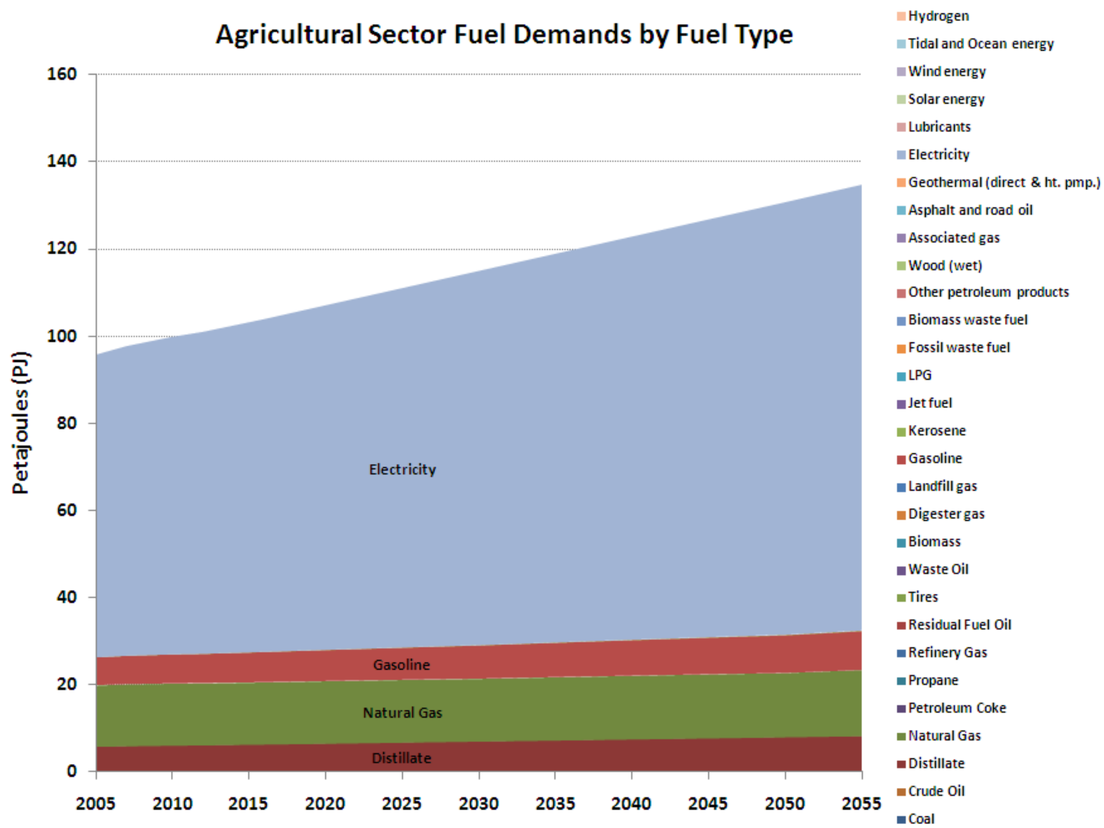


**Figure 33 Useful Energy Demand by Fuel Type in the Agricultural Sector in the Reference Case**

*Transportation Fuels Consumption and Technology Trends*

Final energy demand in the transportation sector is projected to grow strongly in the Reference Case (more than 50% between 2005 and 2050), as shown in Figure 34. (Note that unlike for the ICRA sectors, fuel choice and investment decisions in the transport sector – as in the electric generation and energy supply and conversion sectors – are calculated endogenously by the model. In other words, they are model outputs, not input assumptions.) Increased consumption of diesel, jet fuel, natural gas, and residual fuel oil in the non-LDV subsectors is responsible for much of this growth, while increased ethanol demand (primarily cellulosic ethanol) in the light-duty subsector, particularly in the later years, contributes to a slowing of gasoline demand. A considerable quantity of ethanol is consumed in the form of E-85 fuel (85% ethanol, 15% gasoline, by volume), as opposed to oxygenated gasoline, for which the ethanol blend limit after 2010 is, by assumption, relaxed from 5.7% to 10% (by vol.) – so-called E-10 fuel. After initially being spurred by the biofuels mandates of the RFS, cellulosic ethanol consumption grows on its own, thanks to favorable production economics compared to gasoline, which only becomes more expensive over time due to the ever-increasing cost of crude oil (Figure 25).

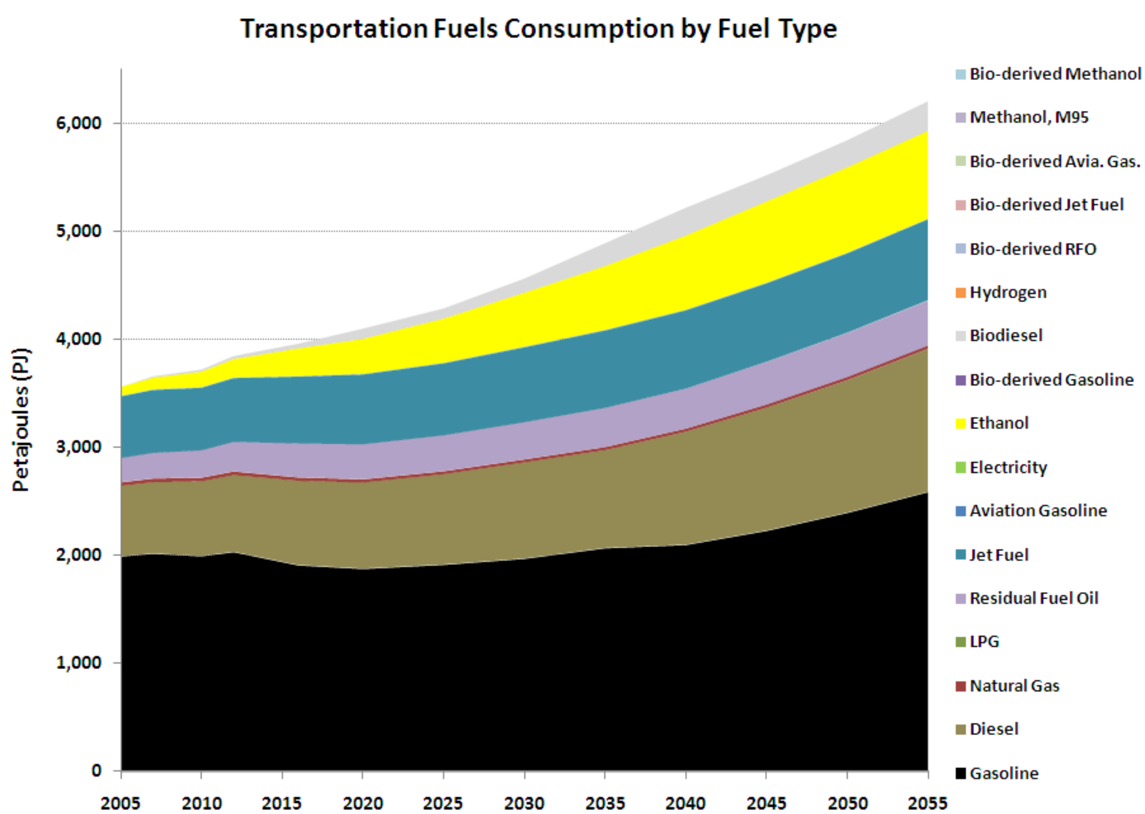


**Figure 34 Final Energy Demand by Fuel Type in the Transportation Sector in the Reference Case**

In fact, biofuels consumption in general takes off in the Reference Case, experiencing a more than 10-fold increase between 2005 and 2050, reaching a combined level of almost

1,050 PJ (~8.0 billion gge) by 2050 (Figure 35). Continued use of imported corn- and sugarcane-based ethanol, combined with an expanding market for biodiesel and cellulosic ethanol, contribute to this strong growth. For the biofuels whose production is explicitly modeled in CA-TIMES (i.e., all except for corn and sugar cane ethanol imports), Figure 36 shows the breakdown of the various biomass feedstock types used for production. Some feedstocks grow more quickly than others and/or are consumed in greater quantities in the near to medium term, i.e., pre-2030 (e.g., Orchard and Vineyard Wastes and the various types of Municipal Solid Waste). Of course, the particular biomass feedstocks the model chooses to use are simply a function of the production economics, specifically the assumed supply curves for each feedstock type, which come from Parker (2010). Site-specific issues and geo-spatial concerns are not explicitly taken into account within the single-region framework of the CA-TIMES model. That being said, the biomass supply curves from Parker (2010) *are* derived from a spatially-explicit geographic information system (GIS) optimization model for biomass production, transport, and conversion to liquid fuel products. Hence, spatial considerations are, at the very least, *not* completely overlooked in the current analysis.

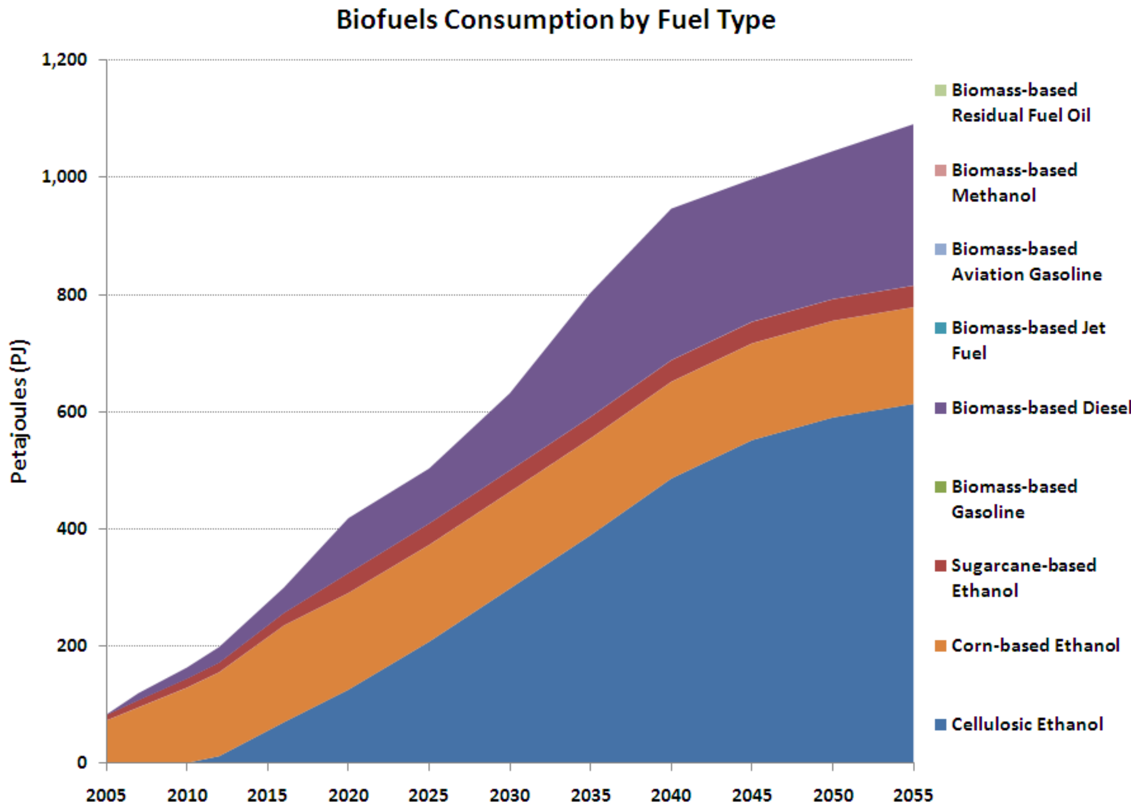


**Figure 35  Biofuels Consumption by Fuel Type in the Reference Case**

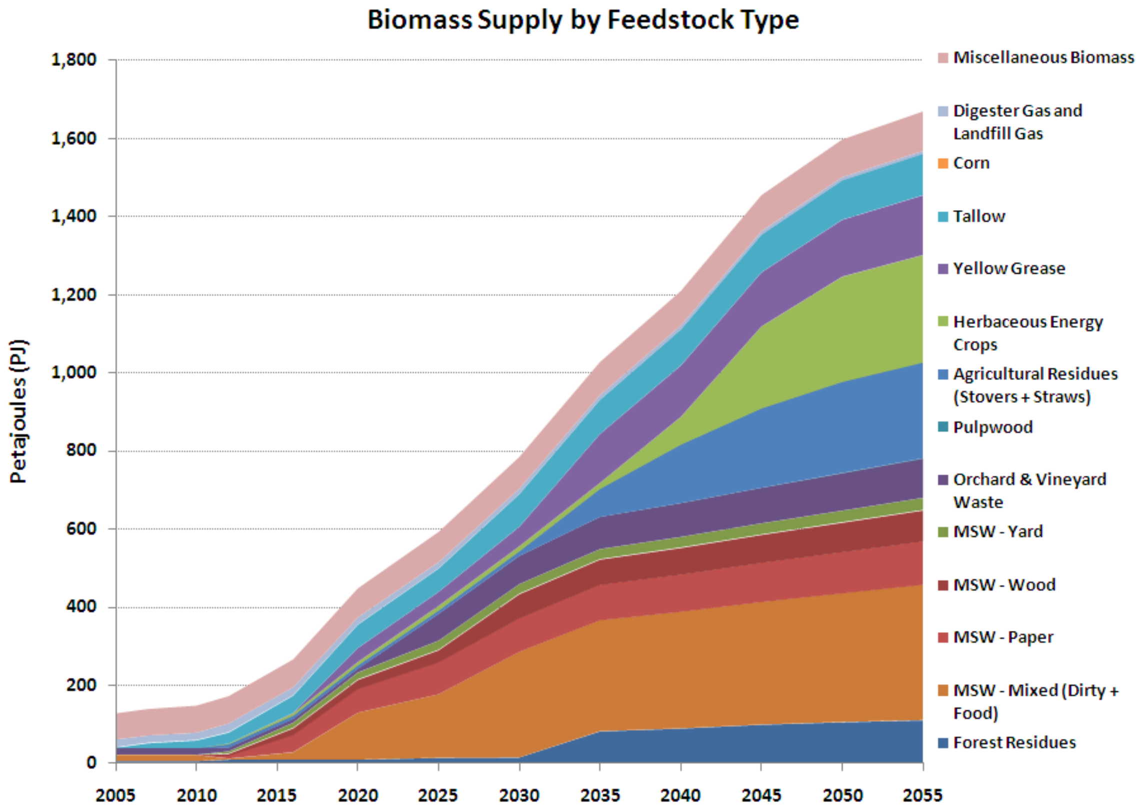


**Figure 36  Biomass Supply by Feedstock Type in the Reference Case**

The previous figures have shown essentially no increased penetration of electricity or hydrogen as transportation fuels in the Reference Case, save for electricity use in the light- and heavy-rail segments.  This result is a function of the economics of these vehicle pathways, including vehicle investment, O&M, and fuel costs, the latter of which depends on the cost of building new fuel conversion facilities and refueling/recharging infrastructure to supply electricity and hydrogen to these vehicles.  The costs of these alternative pathways are further compounded by the higher technology-specific discount rates that are assumed for them in order to better represent consumer behavior (i.e., perceived risk and unfamiliarity with alternative fuel vehicles).  Higher hurdle rates have the impact of increasing annualized investment costs, in effect shortening required payback periods. Hence, the more efficient, though more capital-intensive, vehicle technologies – HEVs, PHEVs, BEVs, and FCVs – become less attractive from the point-of-view of the model, since their fuel savings are not valued quite as much. The hurdle rates assumed in the CA-TIMES model are pulled from different sources – namely, Schäfer and Jacoby (2006) and the U.S. EPA's 9-region MARKAL model (EPA, 2008a). As an example, conventional gasoline and ethanol ICE vehicles are assumed to have a hurdle rate of 18%, gasoline and ethanol HEVs 25%, and BEVs and FCVs 45%.[41]

Over the next several decades, Reference Case energy consumption by light-duty cars and trucks is projected to grow quite significantly (Figure 37) and in addition is expected to maintain its high share of total transportation fuels demand (~50%), even in spite of considerable demand growth expected in the non-LDV subsectors. Unlike today, however, LDV energy demand will be met by more than just oxygenated gasoline. E-85 could also see much more widespread use, due to the biofuels mandates and increasing cost-competitiveness of ethanol relative to gasoline. Such significant market penetration would necessitate a fairly rapid uptake of E-85 Flex Fuel vehicles, especially over the next 10-15 years (Figure 38). Aside from flex fuel technologies, gasoline vehicles continue to remain the dominant technology in the LDV subsector, though not all of these will be of the conventional ICE variety. As Figure 38 shows, both Advanced Gasoline ICEs and Gasoline HEVs achieve significant market share over the next two decades. At first, these more efficient technologies are needed to meet the increasingly stringent CAFE standards of the 2012-2016 time period. But then, the model simply chooses them

[41] A 25% hurdle rate corresponds to a payback period of approximately 4 years, while a 45% payback period is a little more than 2 years.

because, with rising oil prices ($98/barrel in 2020, $111/barrel in 2030, and $125/barrel in 2050), they are more attractive from an economic standpoint (weighing the lifecycle costs of fuel, capital, variable and fixed O&M, and taking into account higher hurdle rates). Due to the rising average fuel economy of the light-duty vehicle fleet (Figure 39), total fuel consumption plateaus over the next decade or so, before re-attaining its historically steep upward trajectory once annual demand growth again overtakes annual efficiency gains. The obvious take-home message from this model result is that increased fuel economy standards can indeed by quite effective at slowing the growth of light-duty vehicle fuel consumption. Though, achieving absolute reductions in fuel use, in the face of continuously increasing demand for light-duty VMT, could be a substantially more difficult challenge altogether.

Note that in Figure 38, the reason conventional Gasoline ICEs re-take their portion of the gasoline vehicle market in the later years is simply because of the exogenously specified inputs for vehicle efficiency, which assume (at the technology level) a slow but sustained rise in conventional ICE vehicle fuel economy over time, even in the absence of more stringent CAFE standards after 2016. This also explains why one observes a “kink” after 2030 in the new model-year vehicle fuel economies shown in Figure 39. Of course, it is entirely possible that, in a BAU baseline future, new vehicle fuel economies never again rise above the 2016 CAFE standard requirement, with automakers choosing to put all propulsion system efficiency gains into increased vehicle weight, higher horsepower, and vehicle acceleration times. After all, this is what we have seen over the past 25 years, and barring increasingly stringent vehicle efficiency and emissions standards and/or high, sustained fuel prices, there is probably no reason to think that the situation going forward will be any different.

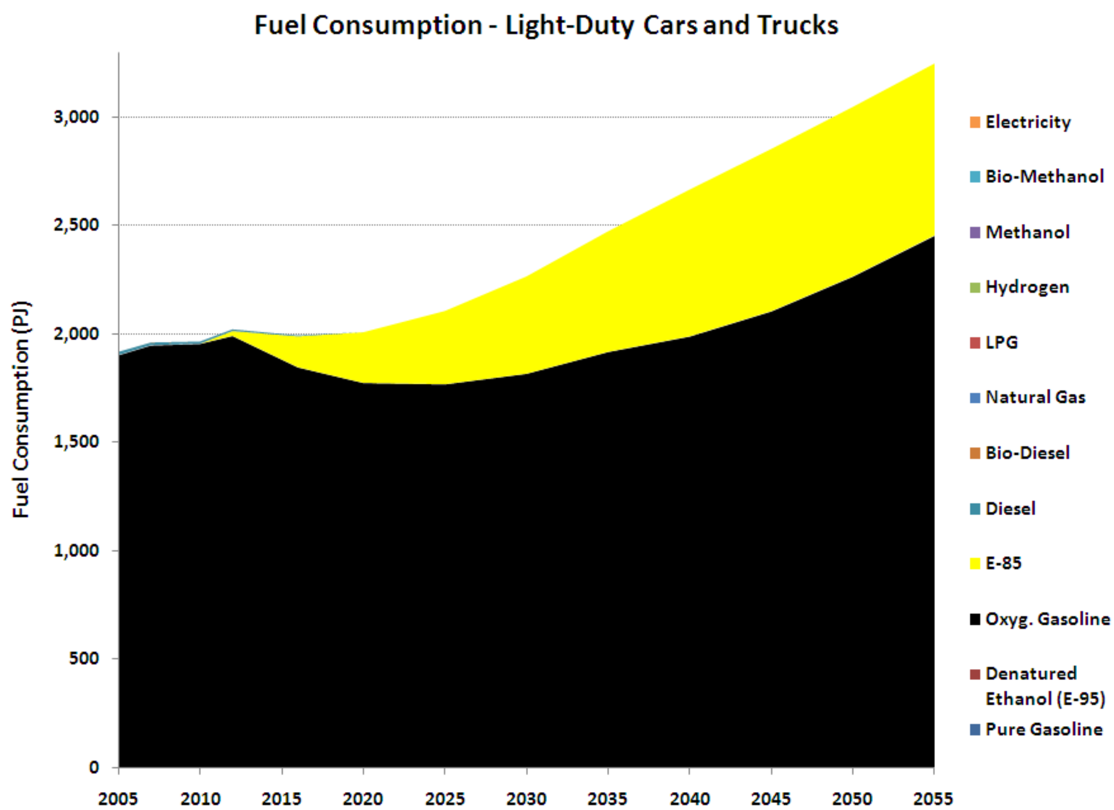


**Figure 37 Fuel Consumption for Light-Duty Vehicles in the Reference Case**

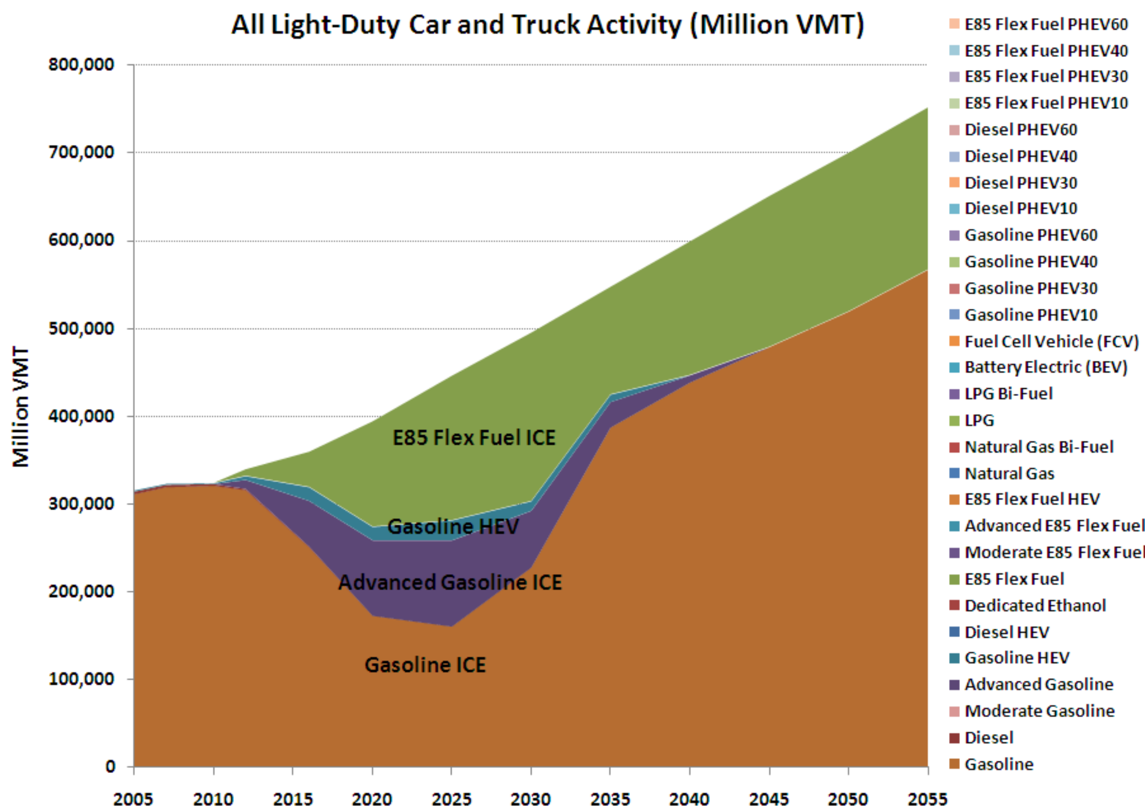


**Figure 38  Technology Penetration in the Light-Duty Vehicle Subsector in the Reference Case**

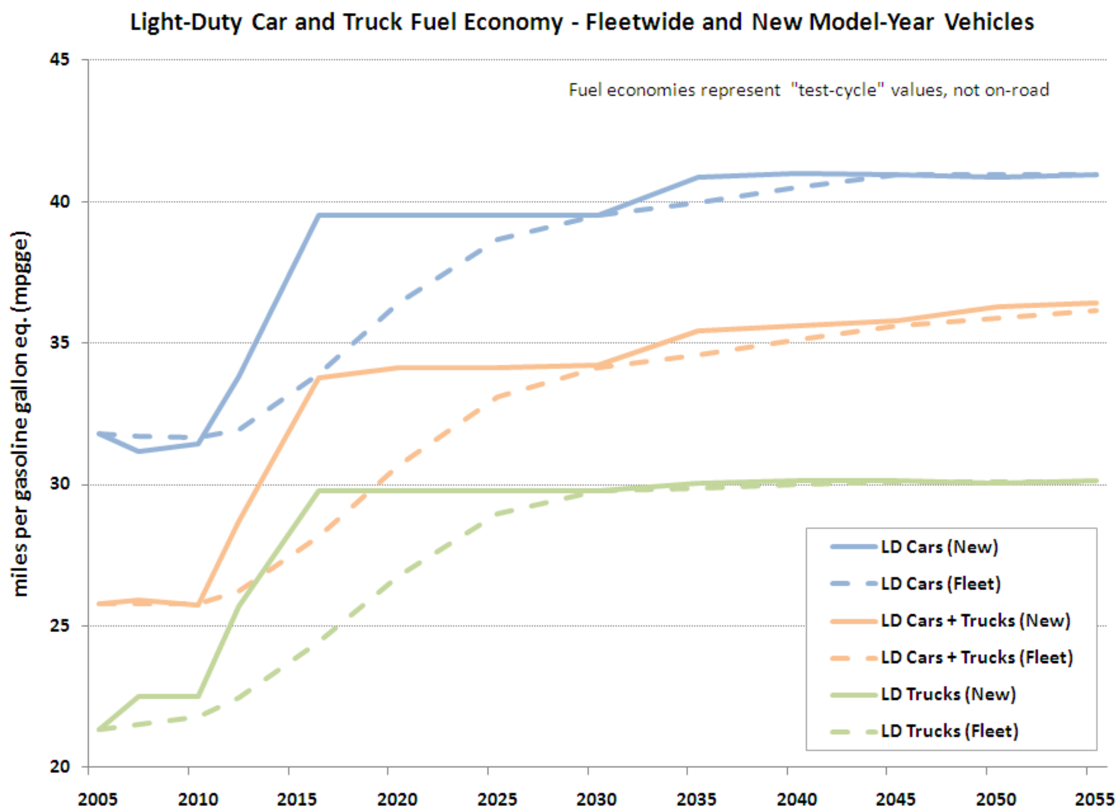


**Figure 39 Average Light-Duty Vehicle Fuel Economy in the Reference Case**

Fuel consumption trends in the non-LDV transport subsectors are, for the most part, in line with what one would typically expect of a Reference Case: the various subsectors continue to look very much like they do today, save for some increased biodiesel consumption as a result of the RFS mandates and, in later years, due to favorable production economics compared to conventional fossil diesel. The only means of producing biodiesel in the Reference Case is via hydrotreatment of yellow grease and animal tallow feedstocks, which are in relatively short supply in comparison to the various types of cellulosic biomass. Moreover, biodiesel production via FT synthesis of these feedstocks remains uncompetitive from a cost perspective in all years, even at high, sustained crude oil prices later in the modeling horizon. If biomass supplies were not so limited, biodiesel consumption would likely capture even greater market share than what we see in the Reference Case. However, as it stands, cellulosic ethanol is the preferred pathway for supplying biofuels. In particular, utilization of a biochemical (hydrolysis) process is the most attractive pathway.

The technology and fuel development trends in the medium-duty truck and bus subsectors are particularly interesting. More specifically, diesel replaces oxygenated gasoline within a specific segment of the medium-duty subsector (Figure 41), a decision made by the model because of the increasing cost competitiveness of diesel vehicles in this segment (namely, fleet delivery trucks). Similarly, natural gas loses market share to diesel in the bus subsector for essentially the same reason (Figure 42): the capital costs of natural gas buses are simply too high, and their efficiencies too low, to make up for the lower cost of natural gas fuel compared to petroleum-based diesel. In considering the likelihood of these findings, it is important to note that in these cases the model does not explicitly take air quality and noise concerns into account during its decision-making process, both of which represent two important motivating factors for why we see natural gas vehicles in cities around the world today.

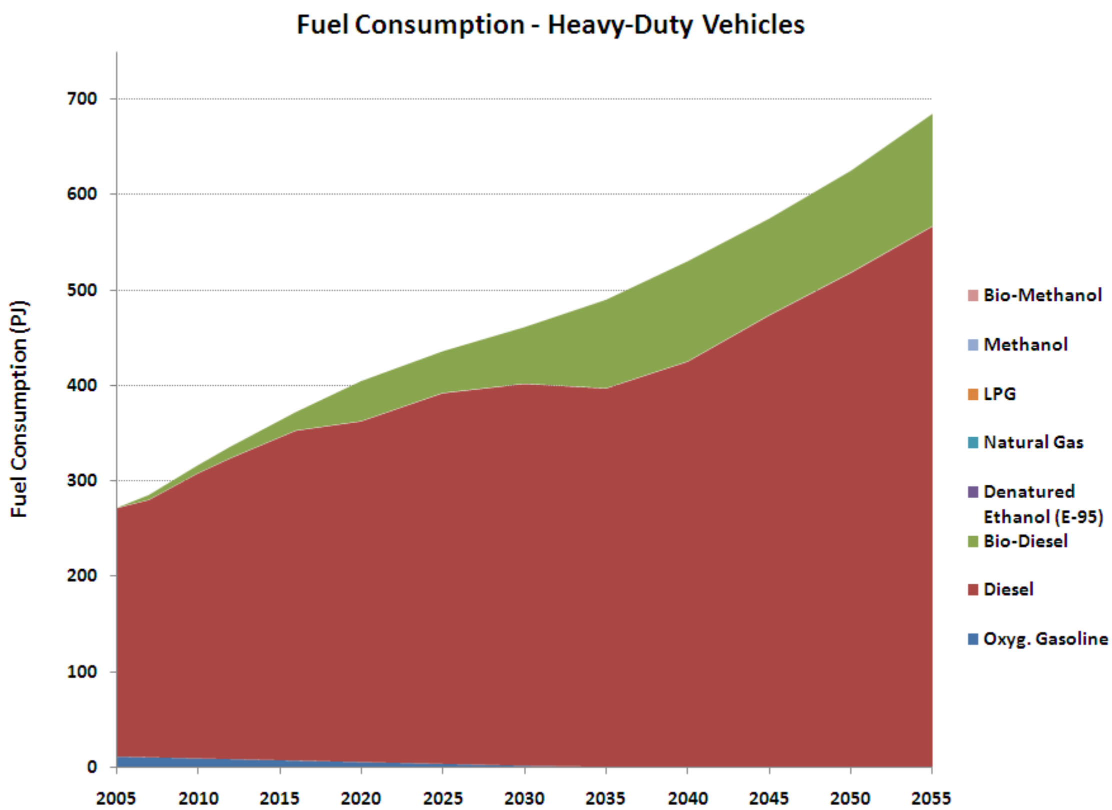


**Figure 40  Fuel Consumption for Heavy-Duty Trucks in the Reference Case**

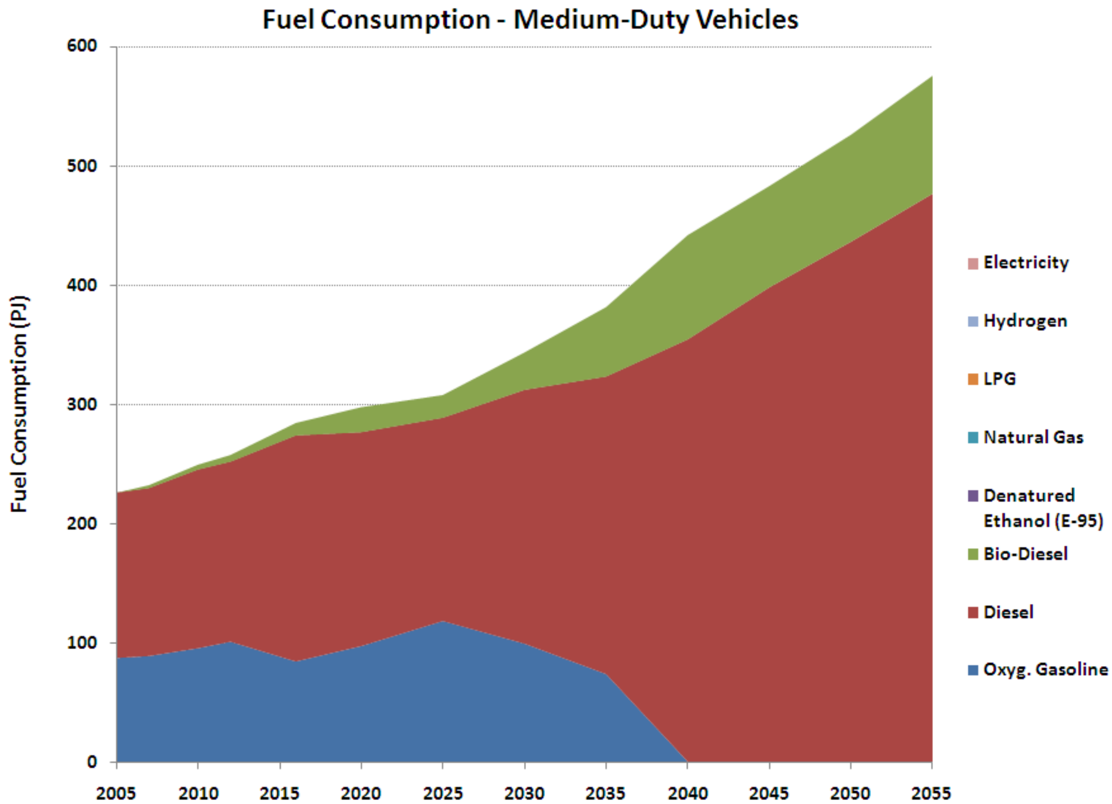


**Figure 41  Fuel Consumption for Medium-Duty Trucks in the Reference Case**

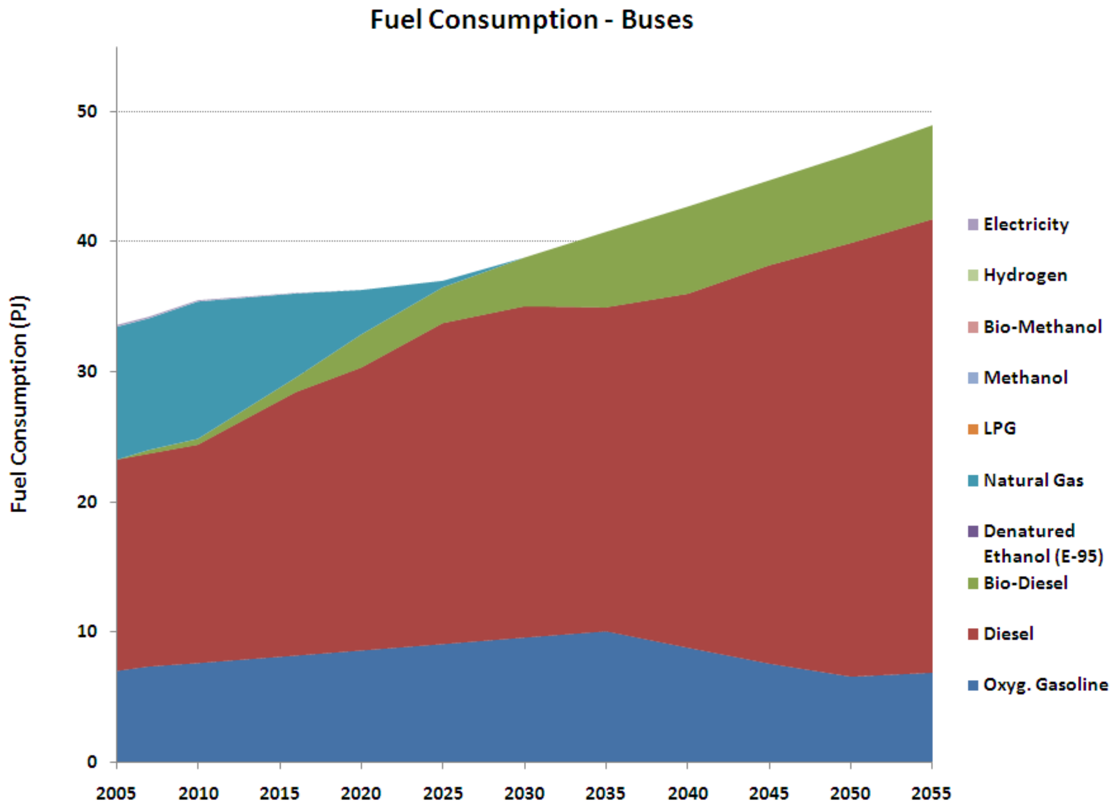


**Figure 42 Fuel Consumption for Buses in the Reference Case**

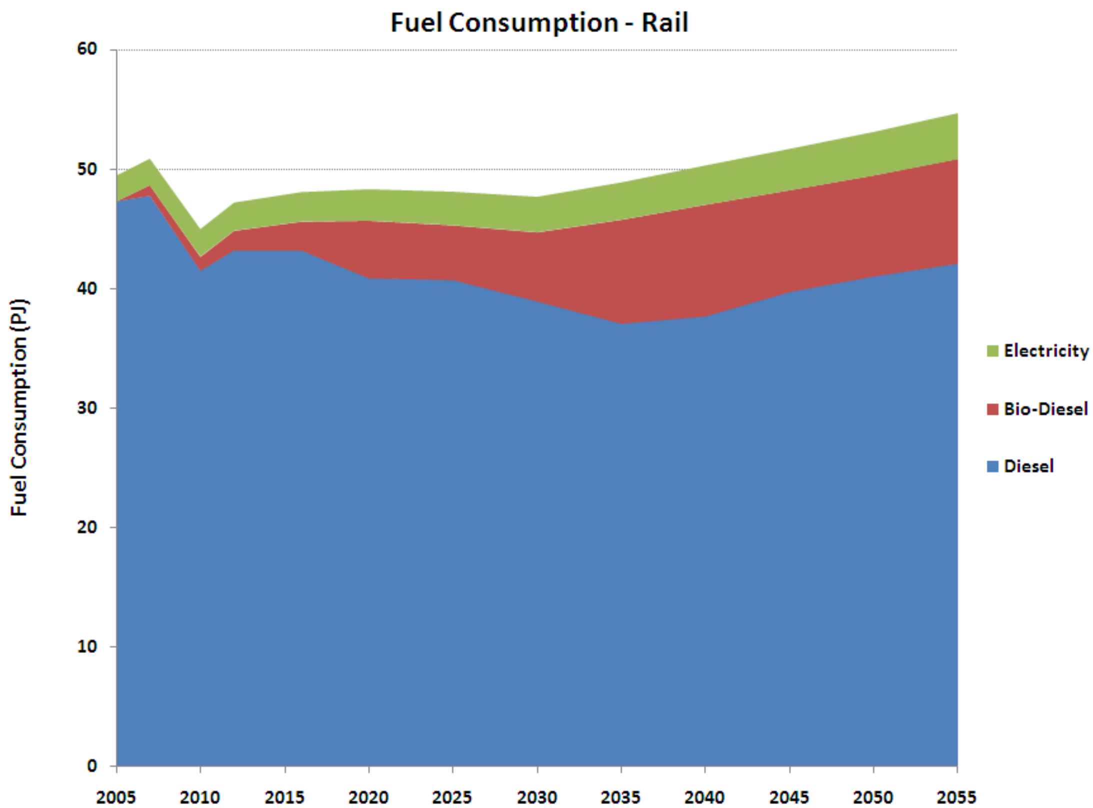


**Figure 43 Fuel Consumption for Rail in the Reference Case**

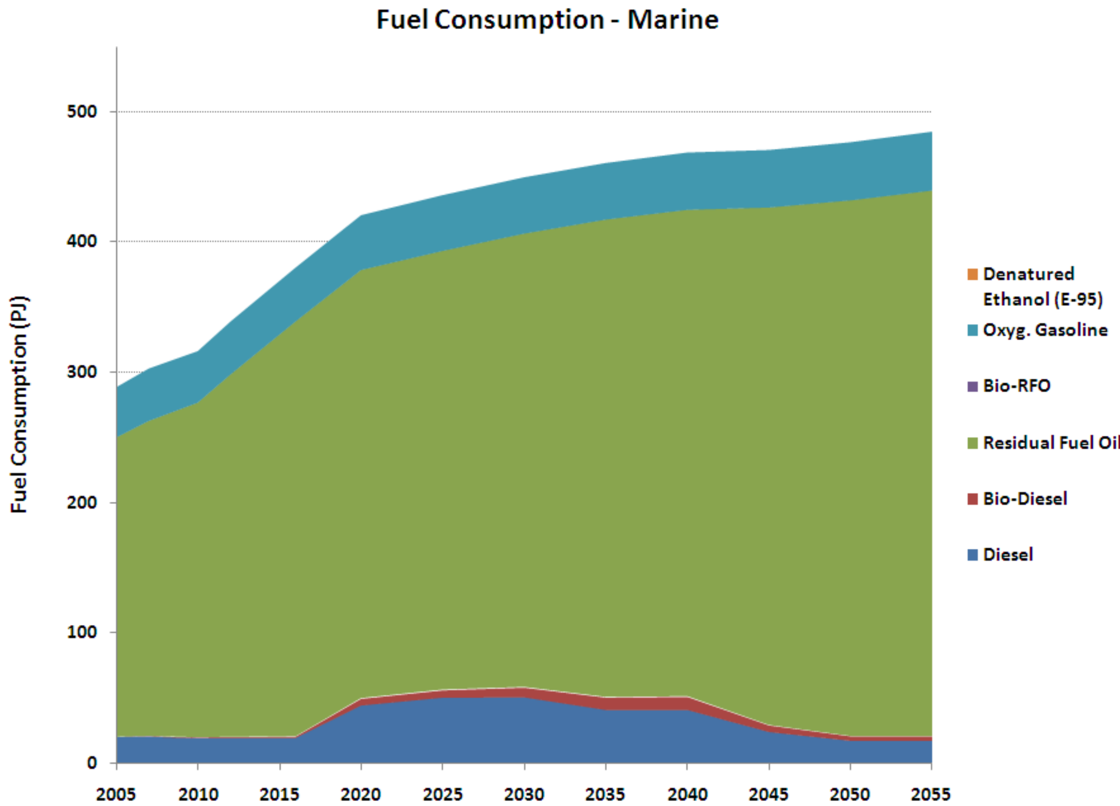


**Figure 44 Fuel Consumption for Marine Vessels in the Reference Case**

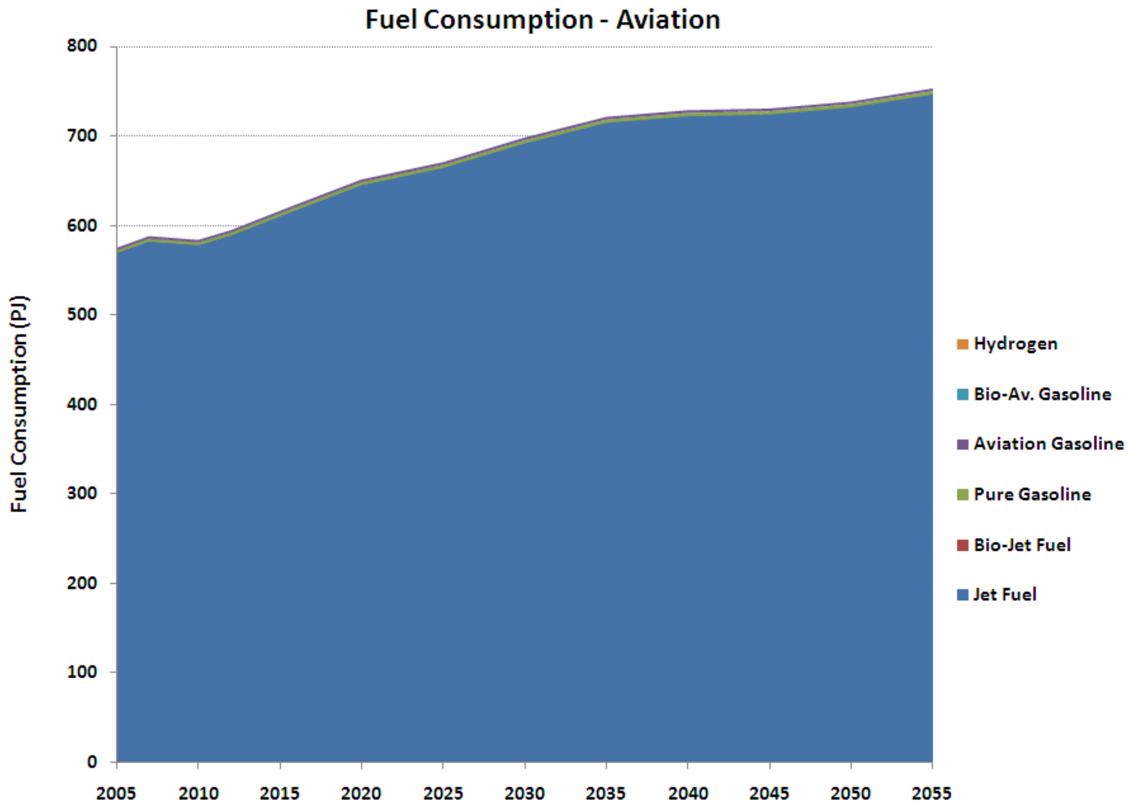


**Figure 45 Fuel Consumption for Aviation in the Reference Case**

*Greenhouse Gas Emissions*

Given the projected increases in service demands and energy consumption in the business-as-usual Reference Case scenario, it is perhaps not surprising that California greenhouse gas emissions are expected to continue to rise over the next several decades. Figure 46 shows CA-TIMES model estimates of *CA-Combustion* GHG emissions[42] produced via fuel combustion activities in each of the various energy producing and consuming sectors. (As discussed in Section II.1.3, the model covers intrastate,

[42] *CA-Combustion* GHGs include all emissions produced from fuel combustion activities within California's borders, from interstate and international aviation and marine trips whose origin is California, and from production of electricity that is consumed in California, even if the plants producing the electricity are located out-of-state. *+Out-of-state Supply* GHGs also include upstream emissions of imported energy commodities, which therefore captures well-to-tank emissions that are generated outside of California.

interstate, and international aviation and marine activities, whereas non-energy GHGs are not estimated at the present time.) The transportation sector remains the single largest emissions category for many years to come, growing its share of total fuel combustion emissions to well over half (~56%) by 2050. The combined industrial/supply sector eventually takes over the second position from the electric sector, whose emissions are about the same in 2050 as they are today. Allocation of electric sector emissions to end-uses (Figure 47) better illustrates the contribution of the industrial, commercial, residential, and agricultural sectors to total GHG emissions. Yet, even under this accounting scheme, it is clear that the transportation sector is poised to drive emissions growth in California in the long term. What is potentially more interesting is the near term, specifically the coming decade up to 2020. Results of the CA-TIMES model show that the currently planned policies of the Reference Case (i.e., those summarized in

Table 30) are not likely to be enough to bring emissions back down to 1990 (or even 2005) levels by 2020. That being said, the new CAFE standards (from 2012 to 2016) and the RFS biofuels mandates (to 2022) do help to slow California's rapid emissions growth quite considerably.

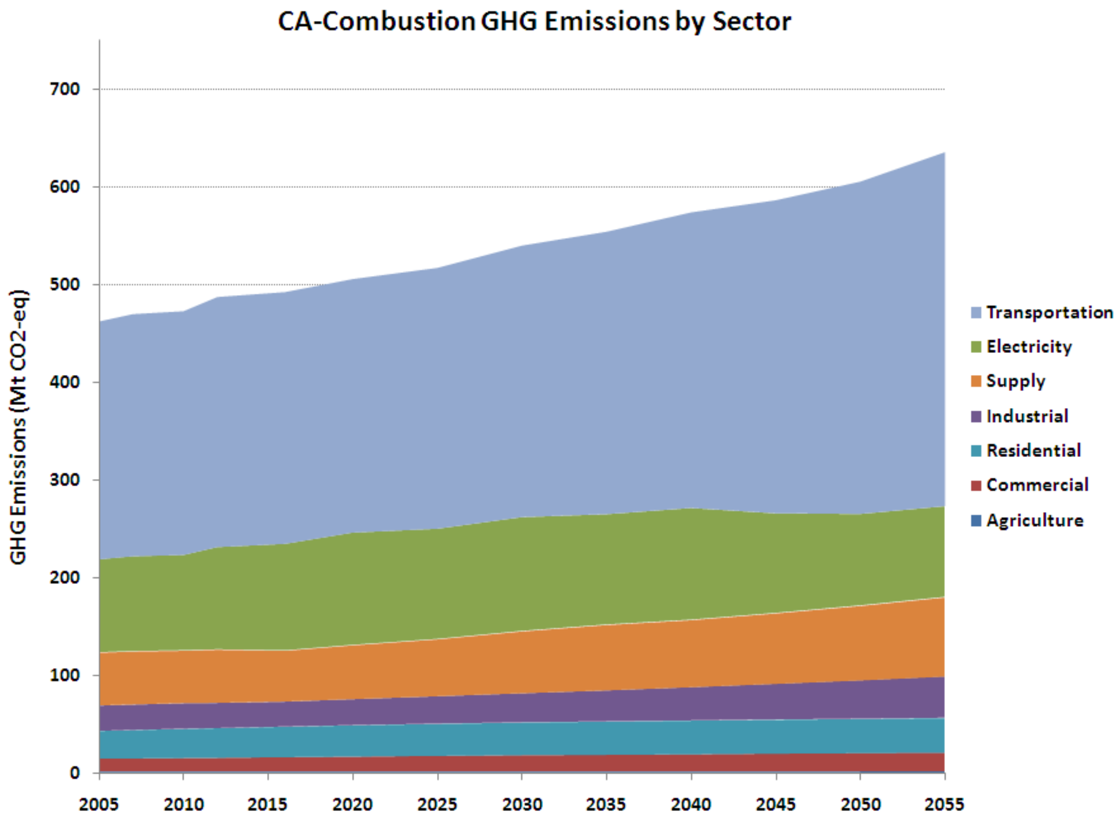


**Figure 46** ***CA-Combustion*** **GHG Emissions by Sector in the Reference Case**

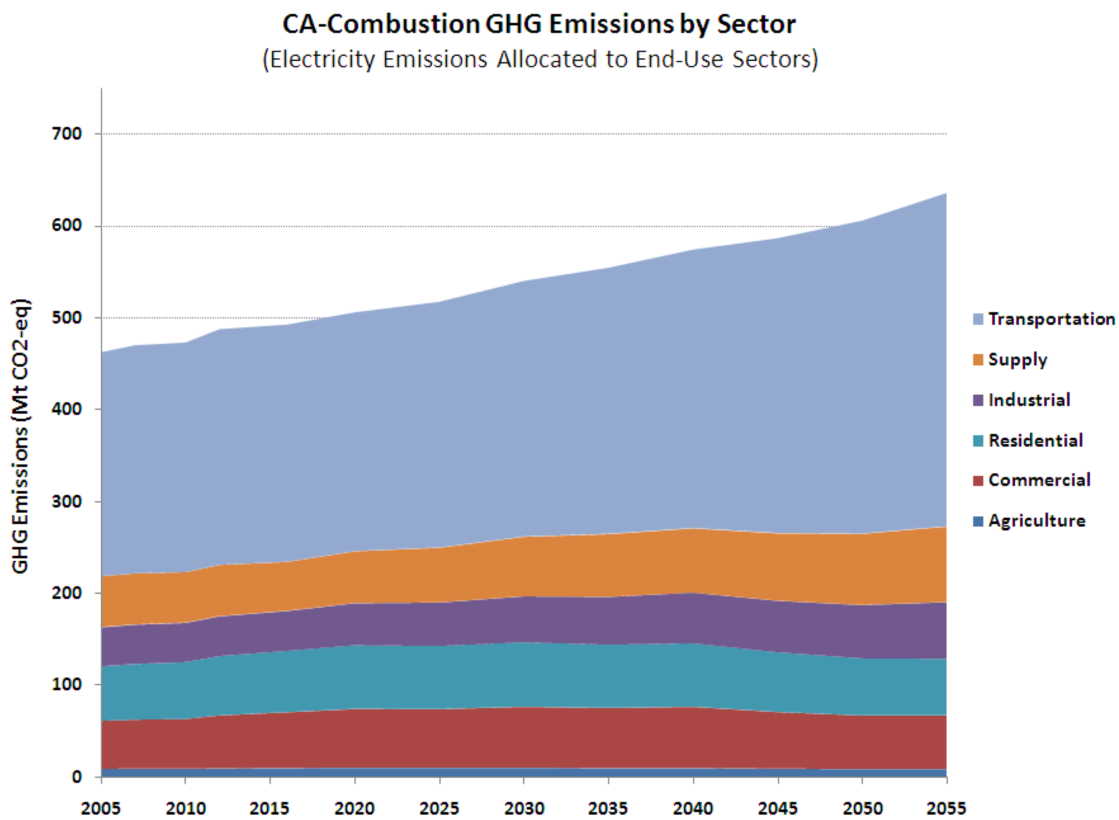


**Figure 47** ***CA-Combustion*** **GHG Emissions by Sector in the Reference Case with Electricity Emissions Allocated to the Various End-Use Sectors**

If one also considers upstream emissions of imported energy commodities (i.e., *+Out-of-state Supply* emissions), the projected future increases in California's GHG emissions become even greater (Figure 48 and Figure 49). The significantly higher growth of supply sector emissions, especially in the long term, is entirely responsible for this result, since emissions from all other sectors are, by definition, the same in both the CA-Combustion and +Out-of-state Supply cases. Allocation of supply sector emissions to each of the end-use sectors, in a way similar to electric sector emissions, is also possible in theory. While not shown here, the likely result of such an allocation would be a further increase in emissions for each of the end-use sectors. The bulk of supply sector emissions in the Reference Case actually occur as a result of crude oil and natural gas extraction and petroleum refining. Therefore, the end-use sectors that consume the most crude-oil- and natural-based fuels (transportation, industrial, and residential) would see particularly large gains in GHG emissions.

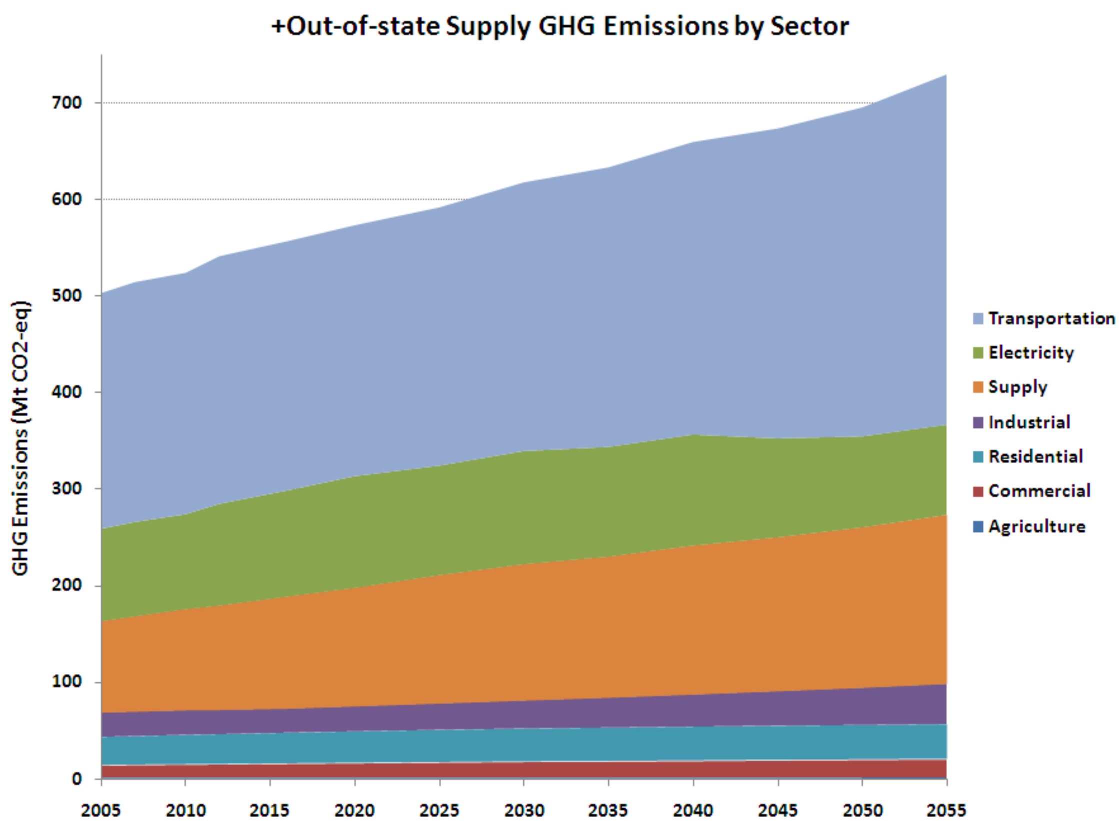


**Figure 48 +*Out-of-state Supply* GHG Emissions by Sector in the Reference Case**

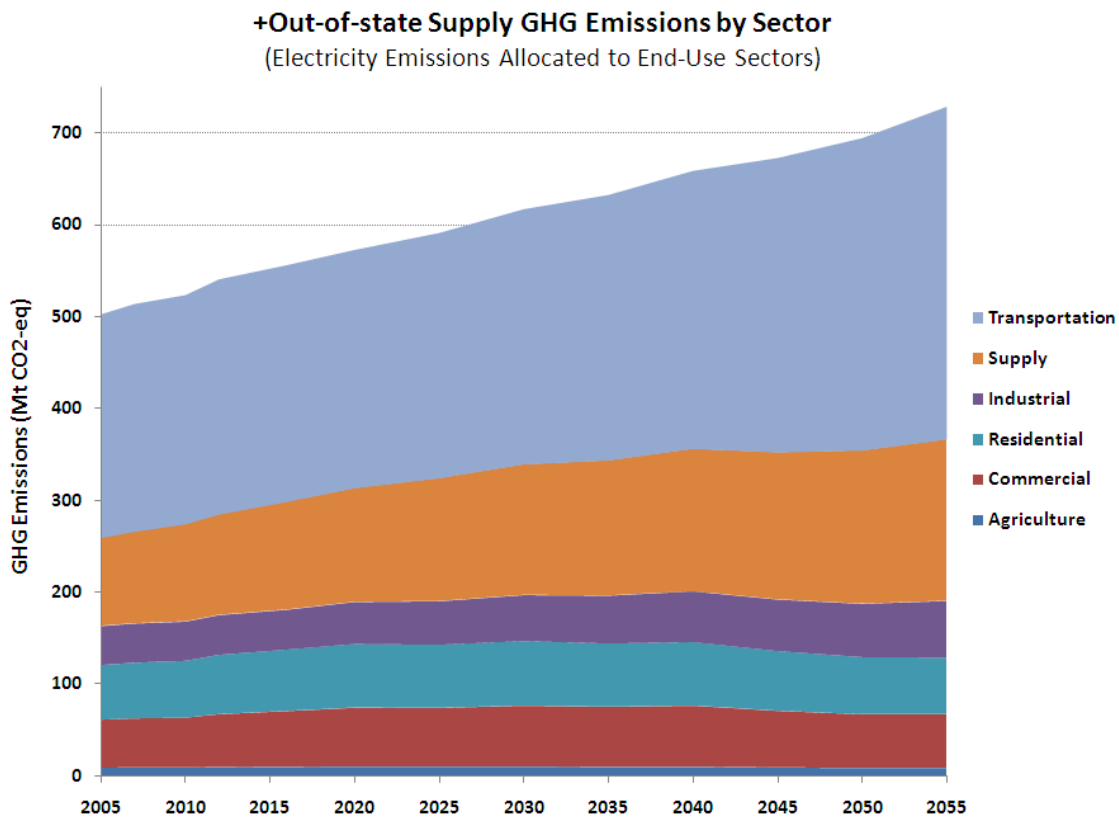


**Figure 49** ***+Out-of-state Supply*** **GHG Emissions by Sector in the Reference Case with Electricity Emissions Allocated to the Various End-Use Sectors**

The implications of allowing California GHG emissions to rise to such high levels in the long term are not entirely certain, principally because the situation depends entirely on how the energy system develops in the rest of the United States and in other countries over the next several decades. If the adoption of advanced technologies and alternative fuels also remains weak throughout the rest of the world, then emissions will continue to rise at a rapid pace, with growth being strongest in developing countries. According to the Intergovernmental Panel on Climate Change (IPCC) 4$^{th}$ Assessment Report, such unrestrained emissions growth could ultimately lead to severe climate change, with global mean surface air temperatures rising by 1.1 to 6.4 ºC ("likely range", depending on scenario and assumptions) over the course of the century (IPCC, 2007). Based on the various computer models used to support the IPCC 4AR, warming of the planet is likely to lead to an increase in the frequency of warm spells, heat waves, and events of heavy rainfall, as well as sea level rise of 18 to 59 cm. These *global* changes will most probably have a pronounced *local* impact here in California, affecting the state's economy, natural and managed ecosystems, and human health and mortality in ways that are hard to predict (California Department of Environmental Protection, 2006).

While transportation-related GHG emissions (including both upstream/ "well-to-tank" and downstream/"tank-to-wheel" stages) rise considerably in the Reference Case, their growth is actually slower than total transport sector energy consumption (see Figure 34). Hence, the average lifecycle carbon intensity of all fuels consumed in the transportation sector decreases, from 82.8 $gCO_2$-eq/$MJ_{HHV}$ in 2005 to 75.1 $gCO_2$-eq/$MJ_{HHV}$ in 2050, a difference of about 10% (Figure 50). Figure 51 shows similar trends for fuels consumed in the light-duty vehicle subsector. (Remember that because these carbon intensities are calculated on a HHV basis, they are about 7 to 11% lower than if calculated on a LHV basis.) Increased consumption of natural gas and biofuels is primarily responsible for lowering average lifecycle carbon intensities. In particular, greater utilization of biofuels raises the relative contribution from upstream fuel production processes and consequently lowers the contribution from downstream fuel combustion activities. Interestingly, in the near term ethanol consumption actually increases the average carbon intensity of LDV fuels, at least according to the results of CA-TIMES, which are based on input assumptions for imported corn and sugar cane ethanol that include significant indirect land use change (iLUC) impacts in their carbon intensity values. For example, the total lifecycle carbon intensity, including iLUC, of corn ethanol is 121.4 $gCO_2$-eq/$MJ_{HHV}$, while for sugar cane ethanol it is 66.3 $gCO_2$-eq/$MJ_{HHV}$, assumptions that are based on CARB (2009b) and Plevin et al. (2010).[43] In addition, the total carbon intensity (including iLUC) of energy crop-derived cellulosic ethanol is assumed to be a much smaller 18.4 $gCO_2$-eq/$MJ_{HHV}$. Of course, in reality, with the LCFS regulations in place, it is unlikely that biofuels with such high iLUC impacts would ever be used in California, and in the Deep GHG Reduction Scenario described later, these two types of ethanol are actually phased out over time.

[43] A median estimate for iLUC of 58.7 $gCO_2$-eq/$MJ_{HHV}$ is assumed for corn ethanol based on Plevin et al. CARB's mean iLUC estimate of 41.5 $gCO_2$-eq/$MJ_{HHV}$ is assumed for sugar cane ethanol from Brazil.

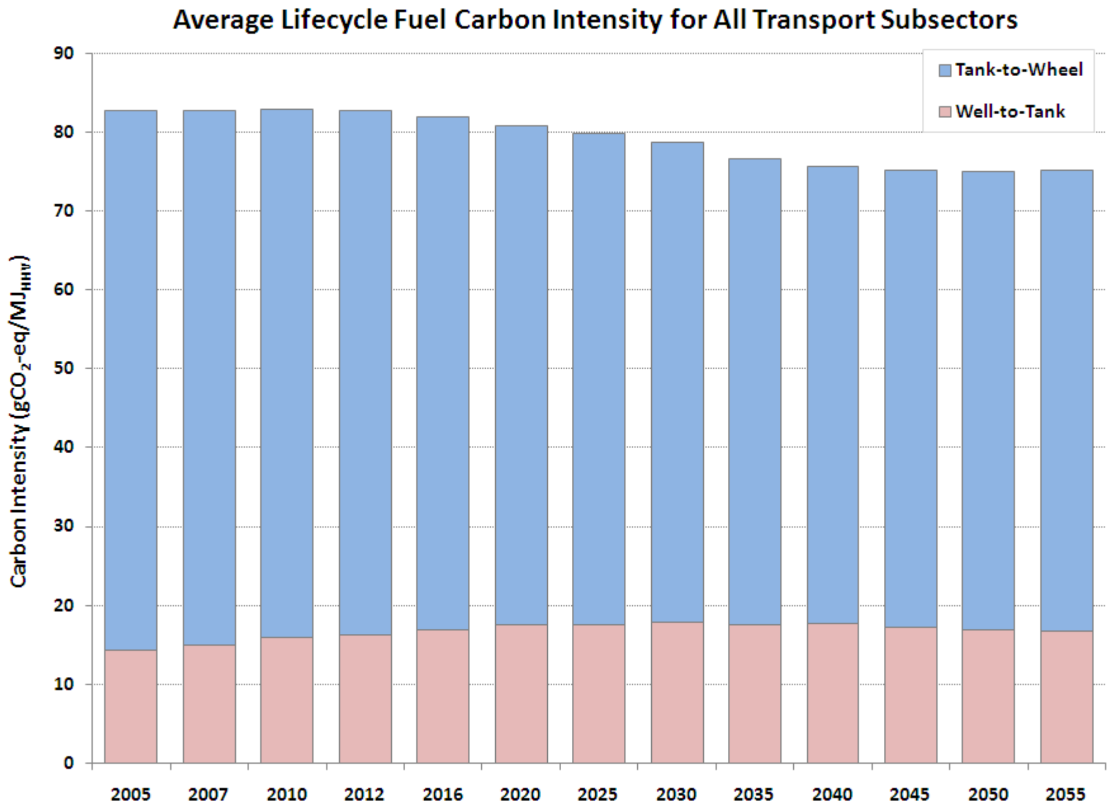


**Figure 50 Average Lifecycle Carbon Intensity of All Fuels Consumed in the Transportation Sector in the Reference Case**

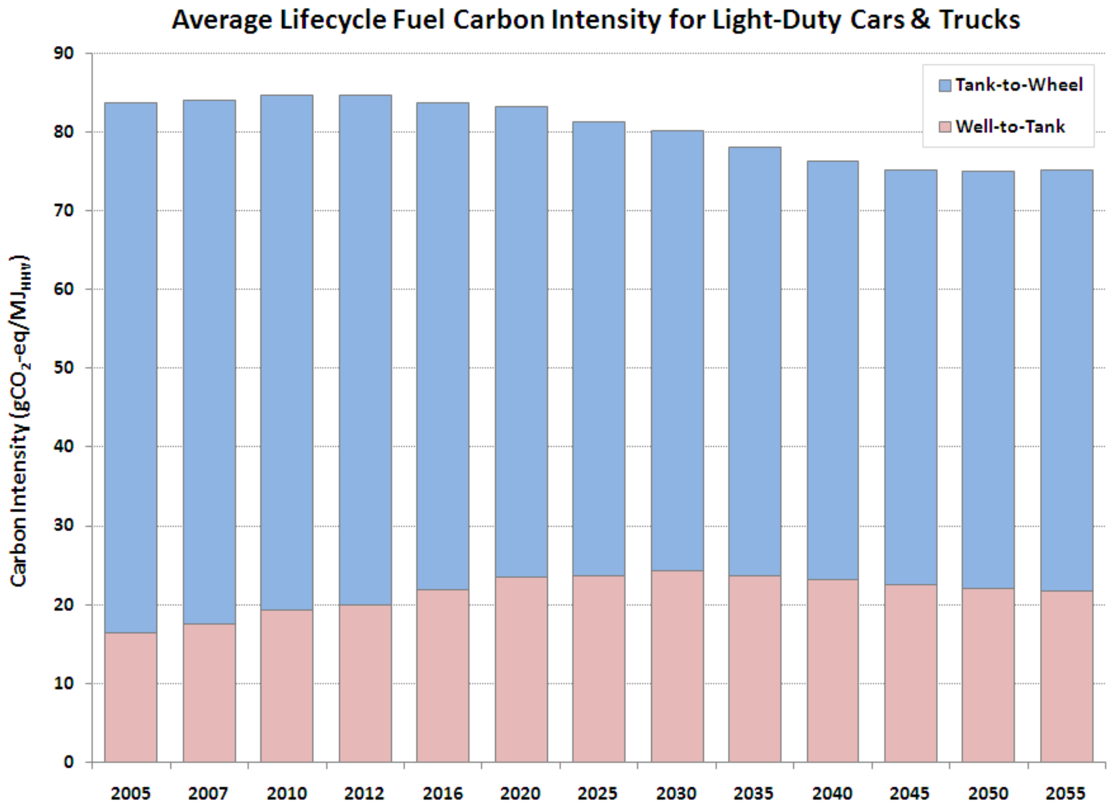


**Figure 51  Average Lifecycle Carbon Intensity of All Fuels Consumed in the Light-Duty Vehicle Subsector in the Reference Case**

### *II.3.2   Deep GHG Reduction Scenario*

The CA-TIMES Deep GHG Reduction Scenario describes the potential development of California's energy system over the next several decades in the context of a social, political, and economic framework that highly values the threat of climate change, both within California and in the rest of the U.S. and the world.  Hence, individuals, firms, and governments all make substantial efforts to transition California toward a low-carbon society.  As with the Reference Case, one should not misconstrue this scenario as a prediction of what will happen as a result of strong climate policy, but rather as a single vision of what *could* feasibly happen, under the large set of technological and policy assumptions input to the model. In theory, an infinite number of GHG reduction scenarios could potentially be developed; however, in order to keep the current analysis manageable and digestible, only a limited number will be discussed here. In particular, I first develop and discuss a Deep GHG Reduction Scenario that achieves an 80% reduction in greenhouse gas emissions below 1990 levels by 2050, with most major advanced technology and alternative fuel options available to the model (at least in the sectors that are represented with bottom-up detail). Then, I develop several interesting variants of this core scenario, most of which do not actually meet the 80% reduction target because the availability of key resources and technologies is limited. The following sections take an in-depth look at the Deep GHG Reduction Scenario and its variants.

### *Notable Modifications of the Reference Case Input Assumptions in Developing the Deep GHG Reduction Scenario*

Policy is undoubtedly the most important driver of the dramatic energy system transition that plays itself out in the Deep GHG Reduction Scenario.[44] The scenario includes all the same policies that are present in the Reference Case, as well as additional policies that would likely also need to be enacted, if the goal were to drive the energy system toward a low-carbon future (Table 31). A few of these policies are already being discussed, the most important of which is the so-called "80in50" target, which calls for an 80% reduction in GHG emissions below 1990 levels by 2050. In reality, this would probably be achieved by a market mechanism such as a cap-and-trade (i.e., emissions trading)

[44] Some might argue that evolving social values, like increased environmental consciousness, will be the most important driver of global change in the future. While this is very much true, I would contend that policy is simply the embodiment of society's collective willingness to enact change.

program or a carbon tax. For simplicity and transparency within the CA-TIMES model, a declining carbon cap constraint is utilized – specifically, a straight line trajectory from 2020 to 2050 is assumed. Other policies included in the Deep GHG Reduction Scenario are renewable portfolio standard on electricity generation and energy efficiency and emissions standards for end-use sector demand technologies (e.g., cars, trucks, heaters, light bulbs, air conditioners, consumer and household electronic appliances, etc.).

**Table 31 Additional Policies Represented in the CA-TIMES Deep GHG Reduction Scenario**

| Policies | Descriptions |
|---|---|
| 80% GHG Reduction Goal by 2050 | - Reduce GHG emissions to 1990 levels by 2020, and 80% below 1990 levels by 2050. Based on a California Executive Order S-3-05. Only applies to fuel combustion emissions in CA-TIMES. Interim emission targets between 2020 and 2050 are linearly interpolated. |
| Renewable Portfolio Standard (RPS) | - By 2020, 33% of California electricity generation must come from renewable sources (excluding hydro). Assumed to remain constant thereafter. Based on Executive Order S-14-08 and Executive Order S-21-09. |
| Light-Duty Vehicle GHG Emission Standards (CAFE for 2017-2025) | - GHG emissions rate of new model-year light-duty cars and trucks declines 4.5% per annum (on a $gCO_2$-eq per mile basis) between 2017 and 2025. Based on notices of intent and an interim technical assessment by DOT-NHTSA, EPA-OTAQ, and CARB, which analyzes the feasibility of an annual rate of improvement of 3 to 6% (EPA-DOT-CARB, 2010).<br>- Light-duty passenger cars: New model-year vehicle fleet must achieve 215 $gCO_2$/mile (41.4 mpg) in 2017, strengthening to 149 $gCO_2$/mile (59.8 mpg) in 2025, assumed to remain constant thereafter.<br>- Light-duty passenger trucks: New model-year vehicle fleet must achieve 285 $gCO_2$/mile (31.2 mpg) in 2017, strengthening to 197 $gCO_2$/mile (45.1 mpg) in 2025, assumed to remain constant thereafter. |
| Energy Efficiency Standards for ICRA Sector Technologies | - Average annual efficiency improvement of generic end-use sector technologies in the Industrial, Commercial, Residential, and Agricultural sectors. Efficiency gains are over and above those assumed in the Reference Case, and are technically feasible with today's technologies. Industrial (0.41% per year); Commercial (0.50% per year); Residential (0.68% per year); Agricultural (0% per year). Based on the *Baseline – high efficiency* scenario of McCarthy et al. (2008b) compared to the *Baseline demand* scenario. |

In addition to policy, the development of the energy system in the Deep GHG Reduction Scenario depends on the multitude of resource, technology, and demand assumptions that are input to the CA-TIMES model. These assumptions are for the most part the same in both the Reference Case and Deep GHG Reduction Scenario. However, in some important instances, they are quite different. The following discussion attempts to summarize the key areas where the inputs diverge.

### Electric Generation Sector

The following two tables summarize the cost and efficiency assumptions of the CA-TIMES model in the Deep GHG Reduction Scenario. The values, which are notably more optimistic than in the Reference Case, are drawn from the EIA's Electricity Module Assumptions to the AEO2010 (EIA, 2010a). More specifically, I utilize a combination of the assumptions used for the EIA's *Low Fossil Technology Cost Case*, *Low Nuclear Cost Case*, and *Low Renewable Technology Cost Case*. Underlying these cases is a storyline where strong policy and R&D efforts lead to significant technological advances and progress along the cost curves for various energy technologies. In other words, the Deep GHG Reduction Scenario exogenously assumes greater technological learning than in the Reference Case, namely because energy R&D (for both fossil and low-carbon technologies) is given much higher priority in a future world where energy and climate become much higher priorities than they are today. These cost reductions and efficiency improvements are achieved for free within the context of the simplified CA-TIMES model (since endogenous technological learning and a top-down macro-economic model are not utilized); though to be sure, these gains would not be achieved for free in reality, give that there are very real costs to R&D spending on the part of public and private entities.

Combined with caps on greenhouse gas emissions, and thus a strong carbon price, and various other energy and environmental policies, the advanced power plant technologies naturally become increasingly attractive. Specifically, the investment costs for coal, natural gas, nuclear, and renewable power plants are 10% lower than in the Reference Case in 2010, and they fall to 25% below Reference Case levels in 2035 and beyond. The cost distribution among the various power plant technologies does not change markedly in the Deep GHG Reduction Scenario compared to the Reference Case: renewables and other advanced technologies (e.g., coal and natural gas with CCS) continue to be more expensive than conventional fossil thermal technologies. Therefore, the main effect is increasing the attractiveness of electricity as an end-use fuel and reducing the cost of electricity produced by renewables and other advanced types of power plants. Lastly, all fixed and variable O&M costs and power plant efficiencies in the Deep GHG Reduction Scenario are assumed to be the same as in the Reference Case.

**Table 32 Investment Cost Assumptions for New Power Plants in the Deep GHG Reduction Scenario**

| Investment Costs for New Power Plants ($/kW) (Notes: Costs are interpolated between the data years shown.) | 2005 | 2015 | 2035 | 2050 |
|---|---|---|---|---|
| Natural Gas Combustion (Gas) Turbine (NGGT) | 685 | 648 | 388 | 388 |
| Advanced Natural Gas Combustion (Gas) Turbine (NGGT) | 648 | 608 | 339 | 339 |
| Natural Gas Combined-Cycle (NGCC) | 984 | 931 | 559 | 559 |
| Advanced Natural Gas Combined-Cycle (NGCC) | 968 | 913 | 524 | 524 |
| Advanced Natural Gas Combined-Cycle (NGCC), w/CCS | 1,932 | 1,787 | 893 | 893 |
| Coal Steam | 2,223 | 2,104 | 1,261 | 1,261 |
| Advanced Coal Int. Gasif. Combined-Cycle (IGCC) | 2,569 | 2,408 | 1,372 | 1,372 |
| Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS | 3,776 | 3,499 | 1,807 | 1,807 |
| Biomass IGCC (Forest Residues) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biomass IGCC (Municipal Solid Waste, Mixed) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biomass IGCC (Municipal Solid Waste, Paper) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biomass IGCC (Municipal Solid Waste, Wood) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biomass IGCC (Municipal Solid Waste, Yard) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biomass IGCC (Orchard and Vineyard Waste) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biomass IGCC (Pulpwood) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biomass IGCC (Agricultural Residues, Stovers/Straws) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biomass IGCC (Energy Crops) | 7,698 | 7,257 | 4,165 | 4,165 |
| Biogas from Landfills and Animal Waste Digesters | 5,199 | 4,901 | 2,813 | 2,813 |
| Geothermal, in California | 3,498 | 3,298 | 1,893 | 1,893 |
| Geothermal, in Western U.S. Outside California | 3,498 | 3,298 | 1,893 | 1,893 |
| Hydroelectric, Conventional | 4,583 | 4,959 | 3,303 | 3,303 |
| Hydroelectric, Reversible (Pumped Storage) | 2,291 | 2,480 | 1,652 | 1,652 |
| Wind, Lower Class Resources in CA | 3,931 | 3,706 | 2,127 | 2,127 |
| Wind, Higher Class Resources in CA | 3,931 | 3,706 | 2,127 | 2,127 |
| Wind, Lower Class Resources in Western U.S. Outside CA | 3,931 | 3,706 | 2,127 | 2,127 |
| Wind, Higher Class Resources in Western U.S. Outside CA | 3,931 | 3,706 | 2,127 | 2,127 |
| Wind, Offshore | 7,874 | 7,423 | 4,260 | 4,260 |
| Solar Thermal, in CA | 8,725 | 8,225 | 5,554 | 5,554 |
| Solar Thermal, in Western U.S. Outside CA | 8,725 | 8,225 | 5,554 | 5,554 |
| Solar Photovoltaic | 10,491 | 9,890 | 6,678 | 6,678 |
| Molten Carbonate Fuel Cell | 9,313 | 8,779 | 5,928 | 5,928 |
| Tidal and Ocean Energy | 14,667 | 12,633 | 8,567 | 6,667 |
| Generic Distributed Generation – Baseload | 1,400 | 1,320 | 758 | 758 |
| Generic Distributed Generation – Peak | 1,681 | 1,585 | 910 | 910 |
| Nuclear, Conventional Light Water Reactors (LWR) | 3,820 | 3,470 | 1,872 | 1,872 |
| Nuclear, Pebble-Bed Modular Reactor (PBMR) | 3,316 | 3,012 | 1,625 | 1,625 |
| Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR) | 2,977 | 2,704 | 1,459 | 1,459 |

Table 33 Efficiency Assumptions for New Power Plants in the Deep GHG Reduction Scenario

**New Power Plant Efficiencies (%)**

*(Notes: For non-geothermal and non-biomass renewables, efficiencies are assumed to be similar to an average fossil-thermal plant. Efficiences are interpolated between the data years shown.)*

| | 2005 | 2035 | 2055 |
|---|---|---|---|
| Natural Gas Combustion (Gas) Turbine (NGGT) | 31.6% | 32.7% | 32.7% |
| Advanced Natural Gas Combustion (Gas) Turbine (NGGT) | 36.7% | 39.9% | 39.9% |
| Natural Gas Combined-Cycle (NGCC) | 47.4% | 50.2% | 50.2% |
| Advanced Natural Gas Combined-Cycle (NGCC) | 50.5% | 53.9% | 53.9% |
| Advanced Natural Gas Combined-Cycle (NGCC), w/CCS | 39.6% | 45.5% | 45.5% |
| Coal Steam | 37.1% | 39.0% | 39.0% |
| Advanced Coal Int. Gasif. Combined-Cycle (IGCC) | 38.9% | 45.8% | 45.8% |
| Advanced Coal Int. Gasif. Combined-Cycle (IGCC), w/ CCS | 31.6% | 41.1% | 41.1% |
| Biomass IGCC (Forest Residues) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Municipal Solid Waste, Mixed) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Municipal Solid Waste, Paper) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Municipal Solid Waste, Wood) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Municipal Solid Waste, Yard) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Orchard and Vineyard Waste) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Pulpwood) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Agricultural Residues, Stovers/Straws) | 36.1% | 43.9% | 43.9% |
| Biomass IGCC (Energy Crops) | 36.1% | 43.9% | 43.9% |
| Biogas from Landfills and Animal Waste Digesters | 25.0% | 25.0% | 25.0% |
| Geothermal, in California | 10.3% | 11.3% | 11.3% |
| Geothermal, in Western U.S. Outside California | 10.3% | 11.3% | 11.3% |
| Hydroelectric, Conventional | 34.5% | 34.5% | 34.5% |
| Hydroelectric, Reversible (Pumped Storage) | 77.5% | 77.5% | 77.5% |
| Wind, Lower Class Resources in CA | 34.5% | 34.5% | 34.5% |
| Wind, Higher Class Resources in CA | 34.5% | 34.5% | 34.5% |
| Wind, Lower Class Resources in Western U.S. Outside CA | 34.5% | 34.5% | 34.5% |
| Wind, Higher Class Resources in Western U.S. Outside CA | 34.5% | 34.5% | 34.5% |
| Wind, Offshore | 34.5% | 34.5% | 34.5% |
| Solar Thermal, in CA | 34.5% | 34.5% | 34.5% |
| Solar Thermal, in Western U.S. Outside CA | 34.5% | 34.5% | 34.5% |
| Solar Photovoltaic | 34.5% | 34.5% | 34.5% |
| Molten Carbonate Fuel Cell | 43.0% | 49.0% | 49.0% |
| Tidal and Ocean Energy | 34.5% | 34.5% | 34.5% |
| Generic Distributed Generation – Baseload | 37.7% | 38.3% | 38.3% |
| Generic Distributed Generation – Peak | 33.9% | 34.5% | 34.5% |

**New Nuclear Plant Efficiencies (tonnes enriched uranium per PJ electricity)**

*(Notes: Efficiences are interpolated between the data years shown.)*

| | 2005 | 2035 | 2055 |
|---|---|---|---|
| Nuclear, Conventional Light Water Reactors (LWR) | 0.65 | 0.65 | 0.65 |
| Nuclear, Pebble-Bed Modular Reactor (PBMR) | 0.36 | 0.36 | 0.36 |
| Nuclear, Gas Turbine - Modular Helium Reactor (GT-MHR) | 0.22 | 0.22 | 0.22 |

**Supply Sector**

Exogenously specified resource price trajectories for crude oil, natural gas, and coal are lower in the Deep GHG Reduction Scenario than in the Reference Case. Up until 2015, the price paths are the same, but eventually there is a divergence in the two, which actually becomes quite pronounced in the later time periods, especially for crude oil (compare Figure 52 with Reference Case Figure 25). The reason for lower fossil fuel prices is that, in a less carbon-intensive world (where other U.S. states and countries are also trying to significantly reduce their GHG emissions), the demand for crude oil, natural gas, and coal will likely be lower than in a BAU future; therefore, fossil prices are likely to fall. At least, this is the storyline underlying the *BLUE Map* scenario of the IEA's Energy Technology Perspective (ETP) 2010 study, which envisions a 50% reduction in global energy-related $CO_2$ emissions below 2005 levels by 2050. In support of this worldwide effort, the IEA estimates that energy-related $CO_2$ emissions in the U.S. and other industrialized nations would have to be reduced by about 80% over this timeframe, implying concomitant reductions in fossil energy consumption of almost the same magnitude.[45] The fossil fuel price projections that I have assumed in the CA-TIMES Deep GHG Reduction Scenario are largely based on the IEA's BLUE Map scenario.[46] As shown in Figure 52, crude oil and natural gas prices increase over the next few years before leveling out at roughly constant values until 2035. Prices then drop

[45] See Chapter 9 of the IEA's 2010 Energy Technology Perspectives report for a U.S.-focused analysis in both BAU and deep GHG reduction scenarios.

[46] Technically, the fossil fuel price projections of the Deep GHG Reduction Scenario are developed by first calculating the price reductions assumed in the IEA's BLUE Map scenario versus their BAU Reference Case, and then second by applying the reduction ratios in each year to the Reference Case fossil fuel price projections of the EIA's AEO2010. The reason for using the EIA projections as a basis is because their numbers are more specific, and arguably more applicable, to the U.S. context.

considerably until 2050 as the world shifts away from fossil fuels to lower-carbon options.

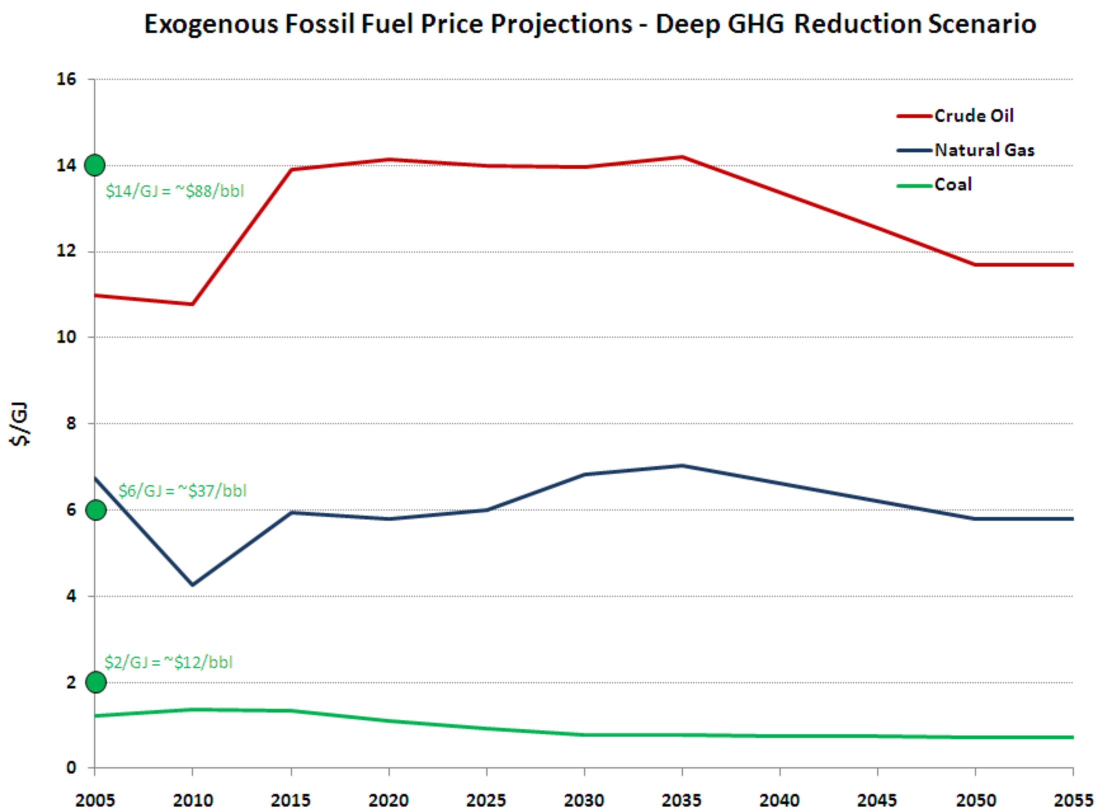


**Figure 52  Exogenous Fossil Fuel Price Projections in the Deep GHG Reduction Scenario**

All other supply sector assumptions and data sources are the same as in the Reference Case.  This includes the biomass supply curves and investment cost and efficiency assumptions for petroleum refineries and cellulosic ethanol, biodiesel, pyrolysis bio-oil, FT poly-generation, and hydrogen production plants (see Section II.2.3 above).

## Transportation Sector

Projections of transportation demand (e.g., in vehicle-miles, passenger-miles, ton-miles, vessel-miles, hours of operation, and so on) in the Deep GHG Reduction Scenario are exogenously specified modifications of the demands in the Reference Case. For certain transport subsectors and segments, these demands are assumed to be higher, while for others they are lower. In the light-duty sector, for instance, lower demands are consistent with a low-carbon scenario storyline. Specifically, I assume that a suite of strong travel demand management (TDM) policies dealing with transit, land use, and auto pricing (e.g., road, cordon, and parking pricing; fuel taxes; and pay-as-you-go insurance) could feasibly reduce VMT 7% (18/21/24%) below Reference Case levels by 2020 (2030/2040/2050). Such VMT reduction potential has been estimated by both Cowart (2008b) and Rodier (2009). In addition, the Deep GHG Reduction Scenario assumes a gradual shift in consumer preferences away from light-duty trucks and toward light-duty cars.[47] Starting from their approximate share of total light-duty vehicle VMT of 53% in 2005, cars are assumed to obtain 55% market share in 2020, 65% in 2030, 70% in 2040, and 75% in 2050. (Compare this to the Reference Case, for which the light-duty car market share is projected to be 51% in 2020, 56% in 2030, 60% in 2040, and 65% in 2050.) Contingent upon these assumptions, the light-duty VMT projections of the Deep GHG Reduction Scenario are shown in Figure 53 (compare to Reference Case Figure 27).

[47] One could imagine this shift occurring for a number of reasons, e.g., high and sustained energy prices: greater environmental consciousness among society; the coming of age of a new generation of drivers for whom “bigger is *not* always better”; and/or a preference for smaller vehicles as urban and suburban spaces become denser and more crowded. Of course, the shift could also happen the other way (toward light-duty trucks), but this outcome would not be entirely consistent with the low-carbon scenario storyline envisioned here.

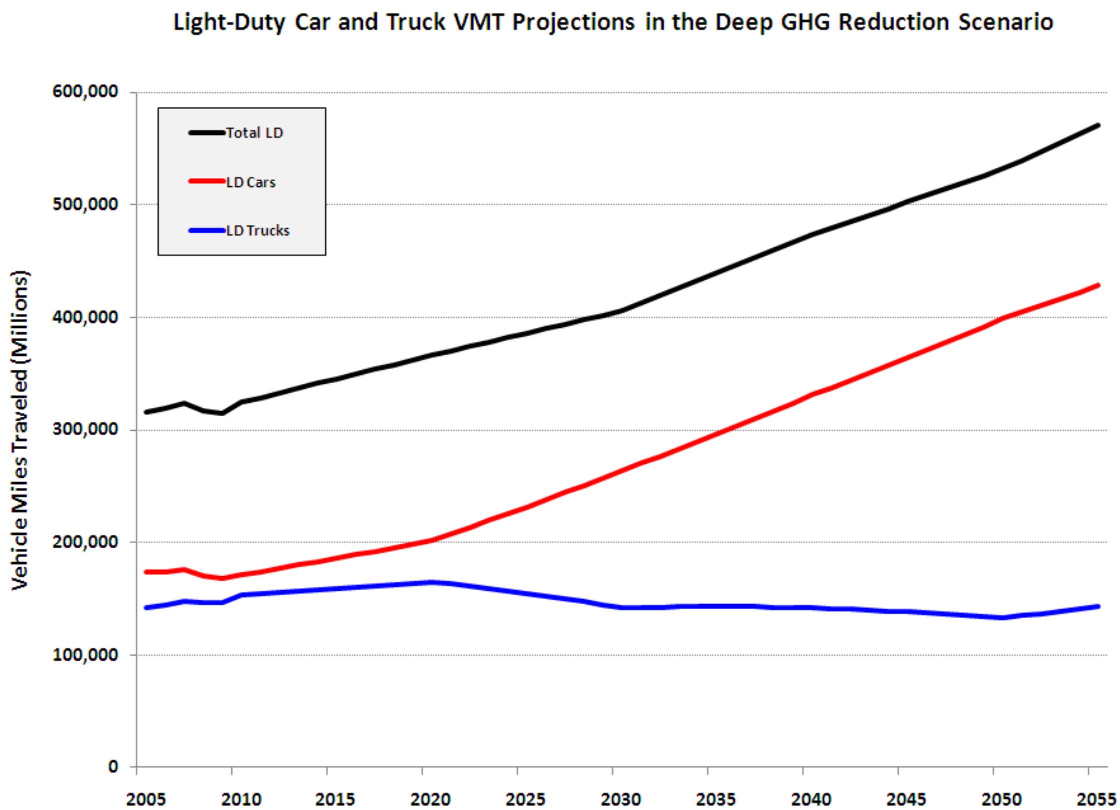


**Figure 53  Light-Duty Car and Truck VMT Projections in the Deep GHG Reduction Scenario**

If transit, land use, and auto pricing policies are the driving force behind the light-duty VMT reductions assumed above, then one would naturally expect the projected future demands for bus and rail transit to rise gradually over time, as they substitute for trips not taken by private motor vehicles.  For this reason, the Deep GHG Reduction Scenario assumes greater demand for urban transit bus VMT and commuter, heavy, and light rail PMT in the future.  More specifically, I assume that one out of every ten vehicle-miles lost by LDVs is shifted to either bus or rail transit.  This is not to say that one out of every ten people, who decide not to drive, end up shifting their mode of travel to bus or rail, but rather the 1/10$^{th}$ factor accounts for the greater occupancy levels that transit vehicles can accommodate (at reasonably high transit ridership levels).  Therefore, not every vehicle-mile of travel that is lost by LDVs is actually gained by bus or rail transit. In fact, some of the VMT would, in effect, disappear, as improved land use patterns and more densely populated cities would allow for shorter trip distances and/or the avoidance of motorized trips in general (i.e., greater number of bike and walk trips).

For all other transport subsectors/segments, the future-year demands assumed in the Deep GHG Reduction Scenario are the same as in the Reference Case (see Section II.2.3).

The cost and efficiency assumptions for certain transportation technologies are also modified in the Deep GHG Reduction Scenario, most notably for light-duty cars and trucks. As in the Reference Case, the LDV input values are largely based on the EIA's AEO2010 assumptions and projections; however, in this instance I use the EIA's *High Technology Case* assumptions for light-duty vehicles as a basis for the CA-TIMES technology characterizations (EIA, 2010a, c). This generally has the effect of reducing the costs of ICEs and HEVs by a small amount, while for BEVs, PHEVs, and FCVs, the differences are much larger. For example, whereas in the Reference Case the cost of lithium-ion batteries is assumed to level out at $500/kWh by 2030, the Deep GHG Reduction Scenario assumes a drop to a much lower $196/kWh by the same year. Similarly, in the Deep GHG Reduction Scenario I assume that fuel cell costs drop to $55/kW by 2030 and are held constant thereafter, well ahead of the Reference Case cost trajectory, which assumes that fuel cell costs are still $139/kW in 2030 and do not reach $55/kW until 2050. Efficiency assumptions are also slightly more optimistic in the EIA's High Technology Case and, thus, in the Deep GHG Reduction Scenario. The following few tables summarize the investment cost and efficiency assumptions for light-duty cars and trucks in the Deep GHG Reduction Scenario. (These can be compared to Reference Case Table 24 and the several tables that come after it.)

**Table 34 Investment Cost Assumptions for New Light-Duty Cars in the Deep GHG Reduction Scenario**

| **Investment Costs for New Light-Duty Cars ($/vehicle)**<br>*(Note: Missing data value indicates that technology is not available in given year.)* | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| | **2005** | **2010** | **2015** | **2020** | **2025** | **2030** | **2035** | **2040** | **2045** | **2050** | **2055** |
| **Gasoline ICE** | 25,775 | 25,924 | 26,141 | 26,544 | 26,648 | 26,809 | 26,990 | 26,990 | 26,990 | 26,990 | 26,990 |
| **Gasoline ICE (Moderate Eff.)** | 26,531 | 26,681 | 26,898 | 27,300 | 27,404 | 27,565 | 27,746 | 27,746 | 27,746 | 27,746 | 27,746 |
| **Gasoline ICE (Advanced Eff.)** | 27,288 | 27,437 | 27,654 | 28,057 | 28,160 | 28,322 | 28,502 | 28,502 | 28,502 | 28,502 | 28,502 |
| **Gasoline HEV** | 29,352 | 29,239 | 28,586 | 28,726 | 28,568 | 28,575 | 28,650 | 28,650 | 28,650 | 28,650 | 28,650 |
| **E85 Flex Fuel ICE** | 26,150 | 26,299 | 26,513 | 26,918 | 27,019 | 27,178 | 27,357 | 27,357 | 27,357 | 27,357 | 27,357 |
| **E85 Flex Fuel ICE (Moderate Eff.)** | 26,906 | 27,055 | 27,269 | 27,674 | 27,776 | 27,934 | 28,114 | 28,114 | 28,114 | 28,114 | 28,114 |
| **E85 Flex Fuel ICE (Advanced Eff.)** | 27,663 | 27,812 | 28,026 | 28,430 | 28,532 | 28,691 | 28,870 | 28,870 | 28,870 | 28,870 | 28,870 |
| **E85 Flex Fuel HEV** | 29,727 | 29,613 | 28,958 | 29,099 | 28,940 | 28,944 | 29,017 | 29,017 | 29,017 | 29,017 | 29,017 |
| **Diesel ICE** | 31,220 | 31,352 | 30,252 | 29,906 | 29,522 | 29,671 | 29,953 | 29,953 | 29,953 | 29,953 | 29,953 |
| **Diesel HEV** | -- | -- | 28,856 | 28,856 | 28,664 | 28,652 | 28,685 | 28,685 | 28,685 | 28,685 | 28,685 |
| **Gasoline PHEV10** | 32,218 | 32,218 | 32,218 | 30,658 | 29,143 | 29,150 | 29,225 | 29,225 | 29,225 | 29,225 | 29,225 |
| **Gasoline PHEV30** | 44,233 | 44,233 | 44,233 | 37,876 | 32,896 | 32,902 | 32,977 | 32,977 | 32,977 | 32,977 | 32,977 |
| **Gasoline PHEV40** | 50,179 | 50,179 | 50,179 | 41,388 | 34,620 | 34,626 | 34,702 | 34,702 | 34,702 | 34,702 | 34,702 |
| **Gasoline PHEV60** | 62,082 | 62,082 | 62,082 | 48,432 | 38,099 | 38,105 | 38,180 | 38,180 | 38,180 | 38,180 | 38,180 |
| **E85 Flex Fuel PHEV10** | 32,590 | 32,590 | 32,590 | 31,031 | 29,515 | 29,519 | 29,593 | 29,593 | 29,593 | 29,593 | 29,593 |
| **E85 Flex Fuel PHEV30** | 44,605 | 44,605 | 44,605 | 38,249 | 33,267 | 33,271 | 33,345 | 33,345 | 33,345 | 33,345 | 33,345 |
| **E85 Flex Fuel PHEV40** | 50,550 | 50,550 | 50,550 | 41,762 | 34,992 | 34,996 | 35,069 | 35,069 | 35,069 | 35,069 | 35,069 |
| **E85 Flex Fuel PHEV60** | 62,454 | 62,454 | 62,454 | 48,806 | 38,470 | 38,474 | 38,548 | 38,548 | 38,548 | 38,548 | 38,548 |
| **Diesel PHEV10** | 30,788 | 30,788 | 30,788 | 30,788 | 29,239 | 29,227 | 29,260 | 29,260 | 29,260 | 29,260 | 29,260 |
| **Diesel PHEV30** | 38,006 | 38,006 | 38,006 | 38,006 | 32,991 | 32,979 | 33,013 | 33,013 | 33,013 | 33,013 | 33,013 |
| **Diesel PHEV40** | 41,518 | 41,518 | 41,518 | 41,518 | 34,715 | 34,703 | 34,737 | 34,737 | 34,737 | 34,737 | 34,737 |
| **Diesel PHEV60** | 48,562 | 48,562 | 48,562 | 48,562 | 38,194 | 38,182 | 38,216 | 38,216 | 38,216 | 38,216 | 38,216 |
| **Battery-Electric** | 77,838 | 72,673 | 67,548 | 69,711 | 61,111 | 54,625 | 54,409 | 54,409 | 54,409 | 54,409 | 54,409 |
| **Hydrogen Fuel Cell** | -- | -- | 68,962 | 58,725 | 50,359 | 43,112 | 39,171 | 39,171 | 39,171 | 39,171 | 39,171 |
| **Gasoline Fuel Cell** | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| **Methanol Fuel Cell** | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| **Dedicated Ethanol ICE** | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| **Natural Gas ICE** | 33,400 | 33,541 | 33,693 | 34,093 | 34,195 | 34,387 | 34,629 | 34,629 | 34,629 | 34,629 | 34,629 |
| **Natural Gas Bi-Fuel ICE** | 32,065 | 32,211 | 32,384 | 32,766 | 32,880 | 33,075 | 33,320 | 33,320 | 33,320 | 33,320 | 33,320 |
| **LPG ICE** | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| **LPG Bi-Fuel ICE** | 31,104 | 31,253 | 31,470 | 31,873 | 31,976 | 32,138 | 32,318 | 32,318 | 32,318 | 32,318 | 32,318 |

**Table 35 Investment Cost Assumptions for New Light-Duty Trucks in the Deep GHG Reduction Scenario**

**Investment Costs for New Light-Duty Trucks ($/vehicle)**

*(Note: Missing data value indicates that technology is not available in given year.)*

| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gasoline ICE | 34,084 | 34,207 | 34,609 | 34,927 | 35,074 | 35,276 | 35,521 | 35,521 | 35,521 | 35,521 | 35,521 |
| Gasoline ICE (Moderate Eff.) | 35,263 | 35,386 | 35,788 | 36,106 | 36,253 | 36,455 | 36,700 | 36,700 | 36,700 | 36,700 | 36,700 |
| Gasoline ICE (Advanced Eff.) | 36,442 | 36,565 | 36,967 | 37,285 | 37,432 | 37,634 | 37,879 | 37,879 | 37,879 | 37,879 | 37,879 |
| Gasoline HEV | 38,276 | 38,123 | 37,576 | 37,398 | 37,194 | 37,267 | 37,401 | 37,401 | 37,401 | 37,401 | 37,401 |
| E85 Flex Fuel ICE | 34,535 | 34,657 | 35,057 | 35,372 | 35,517 | 35,716 | 35,958 | 35,958 | 35,958 | 35,958 | 35,958 |
| E85 Flex Fuel ICE (Moderate Eff.) | 35,714 | 35,836 | 36,236 | 36,551 | 36,696 | 36,895 | 37,137 | 37,137 | 37,137 | 37,137 | 37,137 |
| E85 Flex Fuel ICE (Advanced Eff.) | 36,893 | 37,015 | 37,415 | 37,730 | 37,875 | 38,074 | 38,316 | 38,316 | 38,316 | 38,316 | 38,316 |
| E85 Flex Fuel HEV | 38,726 | 38,573 | 38,024 | 37,843 | 37,636 | 37,707 | 37,838 | 37,838 | 37,838 | 37,838 | 37,838 |
| Diesel ICE | 42,334 | 42,441 | 40,408 | 40,442 | 40,221 | 40,185 | 40,457 | 40,457 | 40,457 | 40,457 | 40,457 |
| Diesel HEV | -- | -- | -- | 37,499 | 37,259 | 37,306 | 37,379 | 37,379 | 37,379 | 37,379 | 37,379 |
| Gasoline PHEV10 | 37,769 | 37,769 | 37,769 | 37,769 | 37,769 | 37,842 | 37,976 | 37,976 | 37,976 | 37,976 | 37,976 |
| Gasoline PHEV30 | 41,521 | 41,521 | 41,521 | 41,521 | 41,521 | 41,595 | 41,729 | 41,729 | 41,729 | 41,729 | 41,729 |
| Gasoline PHEV40 | 43,245 | 43,245 | 43,245 | 43,245 | 43,245 | 43,319 | 43,453 | 43,453 | 43,453 | 43,453 | 43,453 |
| Gasoline PHEV60 | 46,724 | 46,724 | 46,724 | 46,724 | 46,724 | 46,798 | 46,932 | 46,932 | 46,932 | 46,932 | 46,932 |
| E85 Flex Fuel PHEV10 | 38,211 | 38,211 | 38,211 | 38,211 | 38,211 | 38,283 | 38,413 | 38,413 | 38,413 | 38,413 | 38,413 |
| E85 Flex Fuel PHEV30 | 41,964 | 41,964 | 41,964 | 41,964 | 41,964 | 42,035 | 42,166 | 42,166 | 42,166 | 42,166 | 42,166 |
| E85 Flex Fuel PHEV40 | 43,688 | 43,688 | 43,688 | 43,688 | 43,688 | 43,759 | 43,890 | 43,890 | 43,890 | 43,890 | 43,890 |
| E85 Flex Fuel PHEV60 | 47,167 | 47,167 | 47,167 | 47,167 | 47,167 | 47,238 | 47,369 | 47,369 | 47,369 | 47,369 | 47,369 |
| Diesel PHEV10 | 37,834 | 37,834 | 37,834 | 37,834 | 37,834 | 37,881 | 37,954 | 37,954 | 37,954 | 37,954 | 37,954 |
| Diesel PHEV30 | 41,587 | 41,587 | 41,587 | 41,587 | 41,587 | 41,634 | 41,707 | 41,707 | 41,707 | 41,707 | 41,707 |
| Diesel PHEV40 | 43,311 | 43,311 | 43,311 | 43,311 | 43,311 | 43,358 | 43,431 | 43,431 | 43,431 | 43,431 | 43,431 |
| Diesel PHEV60 | 46,790 | 46,790 | 46,790 | 46,790 | 46,790 | 46,837 | 46,910 | 46,910 | 46,910 | 46,910 | 46,910 |
| Battery-Electric | 98,179 | 90,892 | 82,851 | 87,325 | 79,138 | 71,814 | 71,888 | 71,888 | 71,888 | 71,888 | 71,888 |
| Hydrogen Fuel Cell | -- | -- | 74,505 | 63,214 | 53,687 | 45,526 | 40,813 | 40,813 | 40,813 | 40,813 | 40,813 |
| Gasoline Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Methanol Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Dedicated Ethanol ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Natural Gas ICE | 33,503 | 33,584 | 34,022 | 34,421 | 34,513 | 34,640 | 34,807 | 34,807 | 34,807 | 34,807 | 34,807 |
| Natural Gas Bi-Fuel ICE | 32,604 | 32,687 | 33,114 | 33,491 | 33,580 | 33,709 | 33,894 | 33,894 | 33,894 | 33,894 | 33,894 |
| LPG ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| LPG Bi-Fuel ICE | 31,269 | 31,361 | 31,814 | 32,254 | 32,359 | 32,490 | 32,656 | 32,656 | 32,656 | 32,656 | 32,656 |

**Table 36 Fuel Economy Assumptions for New Light-Duty Cars, All Except PHEVs in the Deep GHG Reduction Scenario**

**New Vehicle Fuel Economy (mpgge) - All Except PHEVs**

*(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)*

| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| Gasoline ICE | 31.2 | 31.5 | 34.6 | 37.4 | 38.5 | 39.5 | 41.1 | 41.1 | 41.1 | 41.1 | 41.1 |
| Gasoline ICE (Moderate Eff.) | 35.3 | 35.7 | 39.1 | 42.3 | 43.5 | 44.7 | 46.4 | 46.4 | 46.4 | 46.4 | 46.4 |
| Gasoline ICE (Advanced Eff.) | 40.6 | 41.0 | 45.0 | 48.6 | 50.1 | 51.4 | 53.4 | 53.4 | 53.4 | 53.4 | 53.4 |
| Gasoline HEV | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| E85 Flex Fuel ICE | 31.5 | 31.9 | 34.9 | 37.8 | 38.9 | 39.9 | 41.5 | 41.5 | 41.5 | 41.5 | 41.5 |
| E85 Flex Fuel ICE (Moderate Eff.) | 35.3 | 35.7 | 39.1 | 42.3 | 43.5 | 44.7 | 46.4 | 46.4 | 46.4 | 46.4 | 46.4 |
| E85 Flex Fuel ICE (Advanced Eff.) | 40.6 | 41.0 | 45.0 | 48.6 | 50.1 | 51.4 | 53.4 | 53.4 | 53.4 | 53.4 | 53.4 |
| E85 Flex Fuel HEV | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| Diesel ICE | 39.2 | 39.5 | 42.2 | 45.0 | 46.0 | 46.2 | 45.4 | 45.4 | 45.4 | 45.4 | 45.4 |
| Diesel HEV | -- | -- | 59.6 | 59.3 | 60.5 | 61.2 | 61.5 | 61.5 | 61.5 | 61.5 | 61.5 |
| Battery-Electric | 91.1 | 86.8 | 100.0 | 121.2 | 142.5 | 142.2 | 141.3 | 141.3 | 141.3 | 141.3 | 141.3 |
| Hydrogen Fuel Cell | 74.9 | 75.7 | 83.1 | 89.7 | 92.4 | 94.8 | 98.6 | 98.6 | 98.6 | 98.6 | 98.6 |
| Gasoline Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Methanol Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Dedicated Ethanol ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Natural Gas ICE | 33.2 | 33.4 | 37.0 | 40.4 | 42.1 | 43.0 | 43.9 | 43.9 | 43.9 | 43.9 | 43.9 |
| Natural Gas Bi-Fuel ICE | 30.8 | 31.0 | 34.3 | 37.4 | 39.0 | 40.0 | 41.0 | 41.0 | 41.0 | 41.0 | 41.0 |
| LPG ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| LPG Bi-Fuel ICE | 31.2 | 31.5 | 34.6 | 37.4 | 38.5 | 39.5 | 41.1 | 41.1 | 41.1 | 41.1 | 41.1 |

**Table 37 Fuel Economy Assumptions for New Light-Duty PHEV Cars in the Deep GHG Reduction Scenario**

| New Plug-in Hybrid Vehicle Fuel Economy (mpgge) | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)* | | | | | | | | | | | |
| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
| **Charge-Sustaining Mode** | | | | | | | | | | | |
| Gasoline PHEV10 | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| Gasoline PHEV30 | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| Gasoline PHEV40 | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| Gasoline PHEV60 | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| E85 Flex Fuel PHEV10 | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| E85 Flex Fuel PHEV30 | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| E85 Flex Fuel PHEV40 | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| E85 Flex Fuel PHEV60 | 45.1 | 44.9 | 48.4 | 51.6 | 53.2 | 54.3 | 55.5 | 55.5 | 55.5 | 55.5 | 55.5 |
| Diesel PHEV10 | -- | -- | 59.6 | 59.3 | 60.5 | 61.2 | 61.5 | 61.5 | 61.5 | 61.5 | 61.5 |
| Diesel PHEV30 | -- | -- | 59.6 | 59.3 | 60.5 | 61.2 | 61.5 | 61.5 | 61.5 | 61.5 | 61.5 |
| Diesel PHEV40 | -- | -- | 59.6 | 59.3 | 60.5 | 61.2 | 61.5 | 61.5 | 61.5 | 61.5 | 61.5 |
| Diesel PHEV60 | -- | -- | 59.6 | 59.3 | 60.5 | 61.2 | 61.5 | 61.5 | 61.5 | 61.5 | 61.5 |
| **Charge-Depleting Mode** | | | | | | | | | | | |
| Gasoline PHEV10 | 158.7 | 158.2 | 157.2 | 175.0 | 197.6 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 |
| Gasoline PHEV30 | 156.9 | 156.3 | 155.4 | 170.5 | 189.2 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 |
| Gasoline PHEV40 | 156.9 | 156.3 | 155.4 | 170.5 | 189.2 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 |
| Gasoline PHEV60 | 155.3 | 154.8 | 153.8 | 166.8 | 182.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 |
| E85 Flex Fuel PHEV10 | 158.7 | 158.2 | 157.2 | 175.0 | 197.6 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 |
| E85 Flex Fuel PHEV30 | 156.9 | 156.3 | 155.4 | 170.5 | 189.2 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 |
| E85 Flex Fuel PHEV40 | 156.9 | 156.3 | 155.4 | 170.5 | 189.2 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 |
| E85 Flex Fuel PHEV60 | 155.3 | 154.8 | 153.8 | 166.8 | 182.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 |
| Diesel PHEV10 | -- | -- | 157.2 | 175.0 | 197.6 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 | 227.4 |
| Diesel PHEV30 | -- | -- | 155.4 | 170.5 | 189.2 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 | 212.7 |
| Diesel PHEV40 | -- | -- | 155.4 | 170.5 | 189.2 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 | 208.8 |
| Diesel PHEV60 | -- | -- | 153.8 | 166.8 | 182.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 | 201.4 |

**Table 38 Fuel Economy Assumptions for New Light-Duty Trucks, All Except PHEVs in the Deep GHG Reduction Scenario**

| New Vehicle Fuel Economy (mpgge) - All Except PHEVs | | | | | | | | | | | |
|---|---|---|---|---|---|---|---|---|---|---|---|
| *(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)* | | | | | | | | | | | |
| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
| Gasoline ICE | 22.5 | 22.5 | 24.6 | 27.2 | 29.0 | 30.2 | 31.5 | 31.5 | 31.5 | 31.5 | 31.5 |
| Gasoline ICE (Moderate Eff.) | 26.0 | 26.0 | 28.4 | 31.4 | 33.5 | 34.9 | 36.4 | 36.4 | 36.4 | 36.4 | 36.4 |
| Gasoline ICE (Advanced Eff.) | 30.8 | 30.7 | 33.6 | 37.1 | 39.6 | 41.3 | 43.1 | 43.1 | 43.1 | 43.1 | 43.1 |
| Gasoline HEV | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| E85 Flex Fuel ICE | 22.8 | 22.7 | 24.9 | 27.4 | 29.3 | 30.5 | 31.8 | 31.8 | 31.8 | 31.8 | 31.8 |
| E85 Flex Fuel ICE (Moderate Eff.) | 26.0 | 26.0 | 28.4 | 31.4 | 33.5 | 34.9 | 36.4 | 36.4 | 36.4 | 36.4 | 36.4 |
| E85 Flex Fuel ICE (Advanced Eff.) | 30.8 | 30.7 | 33.6 | 37.1 | 39.6 | 41.3 | 43.1 | 43.1 | 43.1 | 43.1 | 43.1 |
| E85 Flex Fuel HEV | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| Diesel ICE | 28.4 | 28.2 | 30.0 | 32.0 | 33.2 | 34.0 | 34.5 | 34.5 | 34.5 | 34.5 | 34.5 |
| Diesel HEV | 41.2 | 41.2 | 41.2 | 41.2 | 42.2 | 43.2 | 43.7 | 43.7 | 43.7 | 43.7 | 43.7 |
| Battery-Electric | 51.7 | 53.4 | 63.3 | 77.4 | 91.4 | 91.1 | 90.7 | 90.7 | 90.7 | 90.7 | 90.7 |
| Hydrogen Fuel Cell | 54.1 | 54.1 | 59.1 | 65.2 | 69.6 | 72.5 | 75.7 | 75.7 | 75.7 | 75.7 | 75.7 |
| Gasoline Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Methanol Fuel Cell | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Dedicated Ethanol ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| Natural Gas ICE | 25.7 | 25.6 | 27.8 | 30.4 | 31.8 | 32.9 | 34.1 | 34.1 | 34.1 | 34.1 | 34.1 |
| Natural Gas Bi-Fuel ICE | 23.9 | 23.7 | 25.7 | 28.1 | 29.4 | 30.4 | 31.6 | 31.6 | 31.6 | 31.6 | 31.6 |
| LPG ICE | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- | -- |
| LPG Bi-Fuel ICE | 23.9 | 23.8 | 26.2 | 29.6 | 31.6 | 32.9 | 34.1 | 34.1 | 34.1 | 34.1 | 34.1 |

**Table 39 Fuel Economy Assumptions for New Light-Duty PHEV Trucks in the Deep GHG Reduction Scenario**

**New Plug-in Hybrid Vehicle Fuel Economy (mpgge)**

*(Note: Fuel economies correspond to "test-cycle values, not on-road. Missing data value indicates that technology is not available in given year.)*

| | 2005 | 2010 | 2015 | 2020 | 2025 | 2030 | 2035 | 2040 | 2045 | 2050 | 2055 |
|---|---|---|---|---|---|---|---|---|---|---|---|
| **Charge-Sustaining Mode** | | | | | | | | | | | |
| Gasoline PHEV10 | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| Gasoline PHEV30 | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| Gasoline PHEV40 | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| Gasoline PHEV60 | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| E85 Flex Fuel PHEV10 | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| E85 Flex Fuel PHEV30 | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| E85 Flex Fuel PHEV40 | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| E85 Flex Fuel PHEV60 | 32.6 | 32.4 | 35.3 | 38.1 | 40.2 | 41.6 | 42.6 | 42.6 | 42.6 | 42.6 | 42.6 |
| Diesel PHEV10 | 41.2 | 41.2 | 41.2 | 41.2 | 42.2 | 43.2 | 43.7 | 43.7 | 43.7 | 43.7 | 43.7 |
| Diesel PHEV30 | 41.2 | 41.2 | 41.2 | 41.2 | 42.2 | 43.2 | 43.7 | 43.7 | 43.7 | 43.7 | 43.7 |
| Diesel PHEV40 | 41.2 | 41.2 | 41.2 | 41.2 | 42.2 | 43.2 | 43.7 | 43.7 | 43.7 | 43.7 | 43.7 |
| Diesel PHEV60 | 41.2 | 41.2 | 41.2 | 41.2 | 42.2 | 43.2 | 43.7 | 43.7 | 43.7 | 43.7 | 43.7 |
| **Charge-Depleting Mode** | | | | | | | | | | | |
| Gasoline PHEV10 | 158.1 | 158.1 | 158.1 | 158.1 | 158.1 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 |
| Gasoline PHEV30 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 |
| Gasoline PHEV40 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 |
| Gasoline PHEV60 | 145.9 | 145.9 | 145.9 | 145.9 | 145.9 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 |
| E85 Flex Fuel PHEV10 | 158.1 | 158.1 | 158.1 | 158.1 | 158.1 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 |
| E85 Flex Fuel PHEV30 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 |
| E85 Flex Fuel PHEV40 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 |
| E85 Flex Fuel PHEV60 | 145.9 | 145.9 | 145.9 | 145.9 | 145.9 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 |
| Diesel PHEV10 | 158.1 | 158.1 | 158.1 | 158.1 | 158.1 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 | 183.0 |
| Diesel PHEV30 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 | 171.2 |
| Diesel PHEV40 | 151.3 | 151.3 | 151.3 | 151.3 | 151.3 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 | 168.1 |
| Diesel PHEV60 | 145.9 | 145.9 | 145.9 | 145.9 | 145.9 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 | 162.1 |

The cost and efficiency assumptions for technologies in most of the other transport subsectors are the same in the Deep GHG Reduction Scenario as they are in the Reference Case. (Of course, just because an advanced technology, say an electrified railway or hydrogen fuel cell bus, is available to the model in the Reference Case does not necessarily mean that the model will choose it.[48]) An important exception is the aviation subsector, for which cost and efficiency trajectories from the BLUE Map scenario of the IEA's 2008 ETP report are used as a basis for CA-TIMES inputs (IEA, 2008). These assumptions represent a *maximum technology* case in which aircraft energy intensity reductions are 10% below the Reference Case by 2050. (Note that the Reference Case itself already assumes reasonable increases in energy efficiency and

[48] The decision depends on the full lifecycle costs of the technology compared to all other technologies; and since advanced technologies tend to have higher costs, at least when external/social costs are ignored, they are not typically chosen in a BAU Reference Case scenario.

airplane load factors, amounting to a 28% total reduction in aircraft energy intensity between 2005 and 2050.) This should not be confused with an extreme technology case, however. For example, conventional swept-wing body aircraft designs remain the norm in the Deep GHG Reduction Scenario, and new designs (e.g., flying wing and blended wing body aircraft) are not introduced. On the other hand, Deep GHG Reduction Scenario sees an increased utilization of winglets and increased wingspans; light-weighting via advanced materials becomes an important design feature; and more advanced technologies, such as laminar flow control and highly efficient unducted fan open-rotor engines, become more common. In addition, the Deep GHG Reduction Scenario assumes that aircraft energy intensity is reduced by an additional 5% due to air traffic control and operational improvements, such as (1) greater use of continuous descent approaches, (2) improvements in communications, navigation, and surveillance (CNS) and air traffic management (ATM) systems, and/or (3) utilization of multiple stages for long-distance travel (i.e., limiting trip lengths to shorter-distances). (Such operational improvements are the goal of the NextGen project in the U.S. and SESAR in Europe.) In order to make all of these efficiency gains possible, investment costs for aircraft would likely be higher. Therefore, this scenario assumes that the cost difference between conventional aircraft in the Reference Case and advanced aircraft in the Deep GHG Reduction Scenario gradually climbs to 25% by 2050.

**Industrial, Commercial, Residential, and Agricultural Sectors**

In the “ICRA” sectors, future energy demand trajectories and fuel use mixes are exogenously specified by the modeler. Hence, the greenhouse gas reductions that are achieved are entirely a function of the input assumptions. For this reason, it is important that the fuel demands of the Deep GHG Reduction Scenario are consistent with an overall storyline where GHGs are reduced 80% below 1990 levels by 2050, and to this end the IEA's well-known BLUE Map scenario – published in the 2010 ETP study (IEA, 2010) – greatly informs the CA-TIMES Deep GHG Reduction Scenario. In BLUE Map, global energy-related $CO_2$ emissions are reduced 50% below 2005 levels by 2050, with the U.S. and other industrialized countries reducing their emissions by about 80%. In developing this scenario, the IEA partly utilized its global MARKAL energy systems model, which simulates energy investment and fuel use decisions across all regions of the world and in all sectors. These decisions are made based on the least-cost principle, just as in CA-TIMES, in an effort to reflect reality as much as possible. The U.S. is one of many regions in the IEA's global MARKAL model, and I use the results of ETP analysis for the U.S. as a basis for defining the fuel use mixes in the industrial, commercial, residential, and agricultural sectors in 2030 and 2050 in the CA-TIMES Deep GHG Reduction Scenario. Fuel demand shares in the in-between years are automatically calculated by the model via linear interpolation. For a summary of energy use, emissions, and technology development in the industrial and buildings sectors in the IEA's Baseline and BLUE Map scenarios, see Figures 9.10 and 9.14 of the IEA's most recent ETP report (IEA, 2010).

Utilization of U.S.-specific results from another scenario study has some limitations, however. Most notably, the current energy landscape in California is a bit different than it is in the rest of the U.S., and this is likely to remain the case for some time into the future. For instance, because the state is not home to certain heavy industries (e.g., steel-making), only a small amount of coal is consumed in the industrial sector. Also, due to California's relatively temperate climate, heating demands are not as high as in other parts of the country, and for historical reasons heating oil is not a commonly used fuel in the commercial and residential sectors. Previous sections have shown that California currently relies heavily on natural gas and electricity in each of the ICRA sectors; as a result, the carbon intensity of state's end-use sectors, aside from transport, is lower in than in other parts of the country. Assuming these trends continue in the long term (i.e., assuming that California remains ahead of other states on the "carbon intensity curve" and continues on its path toward being a post-industrial, service-oriented, information-based economy), and drawing on the results of the IEA BLUE Map scenario, it is perhaps reasonable to assume that a dramatic transition to a low-carbon economy in California could potentially lead to much greater use of electricity as an end-use fuel, even moreso than today. In the cases where electricity is not a satisfactory alternative, such as steam generation and other high-temperature processes, natural gas or biomass could become attractive low-carbon options. Such a storyline forms the basis of the fuel use mix assumptions of the ICRA sectors in the Deep GHG Reduction Scenario.

Furthermore, the projected demands for each of the ICRA sectors (except for Agriculture) are lower in the Deep GHG Reduction Scenario than in the Reference Case. In particular, the projections are based on the *Baseline – high efficiency* scenario developed for the California Energy Commission as part of the UC-Davis Advanced Energy Pathways (AEP) project (McCarthy et al., 2008a, b). Motivating these demand reductions are energy efficiency and conservation efforts, spurred by a strong carbon price and efficiency standards on end-use technologies (as described in Table 31). The annual efficiency improvements assumed in the Deep GHG Reduction Scenario (0% to 0.7% depending on the end-use sector), which are over and above those already embedded in the Reference Case, are technically feasible with today's technologies (McCarthy et al., 2008a, b).

The Deep GHG Reduction Scenario also assumes that carbon capture and storage technologies are increasingly utilized for a certain portion of fuel combustion in the industrial sector. Specifically, CCS is applied to ten percent (10%) of $CO_2$ emissions from natural gas, biomass, and coal (where utilized) combustion processes in 2030, a share that rises to 75% in 2050. Values in the in-between years are calculated by linear interpolation. The assumed capture rate for all of these generic CCS processes is 90%.

*Results of the Deep GHG Reduction Scenario*

**Electricity Generation**

The development of the electric sector in the Deep GHG Reduction Scenario is markedly different than in the Reference Case (Figure 54). For starters, the sheer magnitude of electricity generation is substantially greater in this scenario, as a result of the increased electrification of the end-use sectors. In 2050, electricity supply is 36% greater than in the Reference Case, and compared to 2005, it is 105% greater. Second, over time natural gas ceases to be the preferred method of generation; instead, the generation mix becomes much more diverse. Of the natural gas generation that still lingers in 2050, most is equipped with carbon capture and storage. Coal IGCC plants with CCS also achieve significant market share in the later time periods. In order to achieve deep reductions in GHG emissions, however, zero-carbon electricity must grow significantly in the years ahead. For this reason the scenario sees a large uptake of new nuclear plants (particularly of the advanced light water reactor variety) and of renewables (solar, wind, geothermal, biomass). In addition, a small but non-trivial amount of electric generation comes from bio-refineries and FT poly-generation plants. The primary purpose of these facilities is to produce liquid fuels, but they also happen to produce low-carbon electricity as a co-product; thus, they are especially attractive to the model.

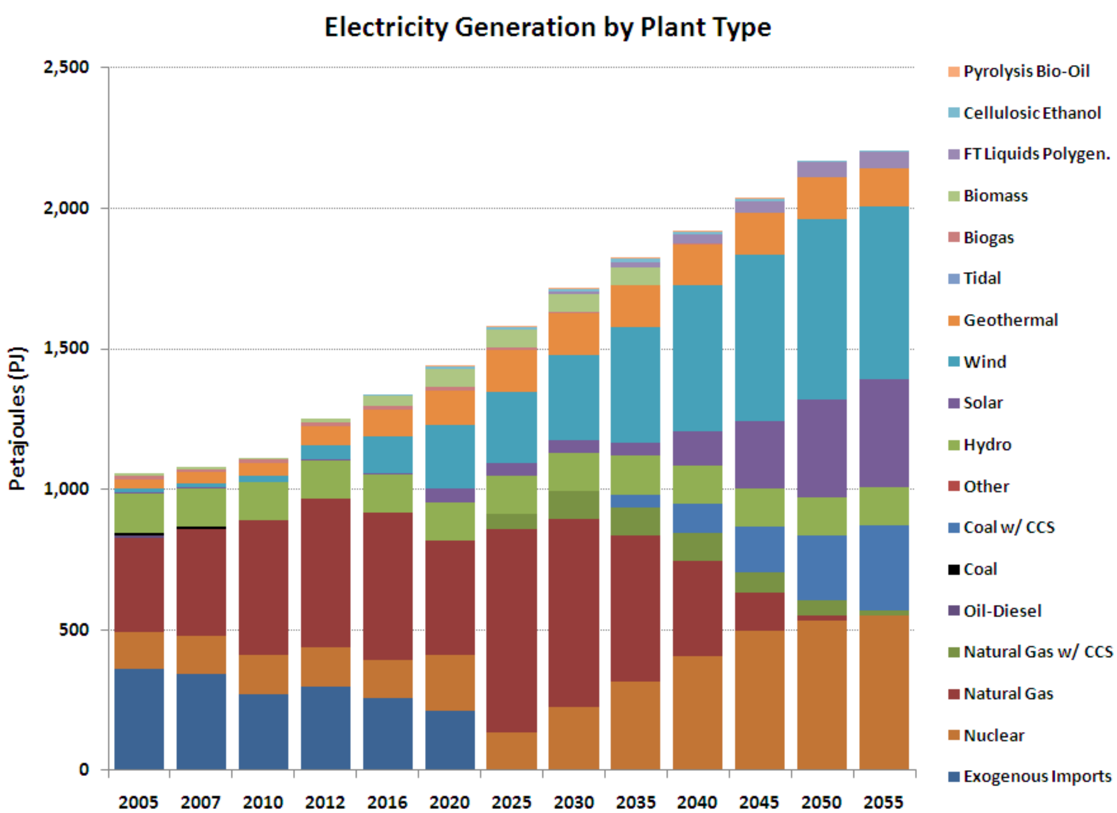


**Figure 54 Electricity Generation by Plant Type in the Deep GHG Reduction Scenario**

Figure 55 shows the dramatic growth of low- and zero-carbon electric generation over time in the Deep GHG Reduction Scenario. By 2050, more than 80% of all California's electricity is produced by zero-carbon sources (nuclear, hydro, and other renewables), with the remainder coming from biomass and fossil power plants equipped with CCS. In particular, the share of non-hydro renewables in the generation mix grows to approximately 50% in 2050, a fairly high level in light of intermittency concerns with solar and wind power. Whether or not the vast array of renewable resources (not all of which are intermittent) could reliably supply such a large share of California's electricity demand is still an open question, and one this analysis only begins to address. To some extent, both geothermal and solar thermal technologies have the potential to act as baseload generators; however, the intermittency of wind power could become a major challenge without adequate electrical storage capacity. On these points, it is important to note that the Deep GHG Reduction Scenario assumes no additional storage capacity than what already exists in California's power system today (i.e., a small amount of pumped storage). Moreover, while the CA-TIMES model is not able to represent the timing of electricity supply and demand in the way that a full-blown electricity dispatch model is able to do, its high timeslice resolution nevertheless allows it to do a fairly reasonable job. Even though no constraints have been introduced to the model to limit the share of generation from particular renewable technologies in a given year (as is common practice in other energy systems models), CA-TIMES has full knowledge of end-use electricity demands and the availability of renewable resource supplies in all timeslices. Therefore, in some sense the model is capable of acting as a judge for how much electricity could be feasibly supplied from renewables in any future time period. Lastly, it is important to note that the total generation potential from each of the various renewable resource types is constrained based on total renewable resource estimates for California and the western United States, which are found in the California Public Utility Commission's "33% RPS Implementation Analysis" (CPUC, 2009). Only a share of these total resources are made available to the California market.

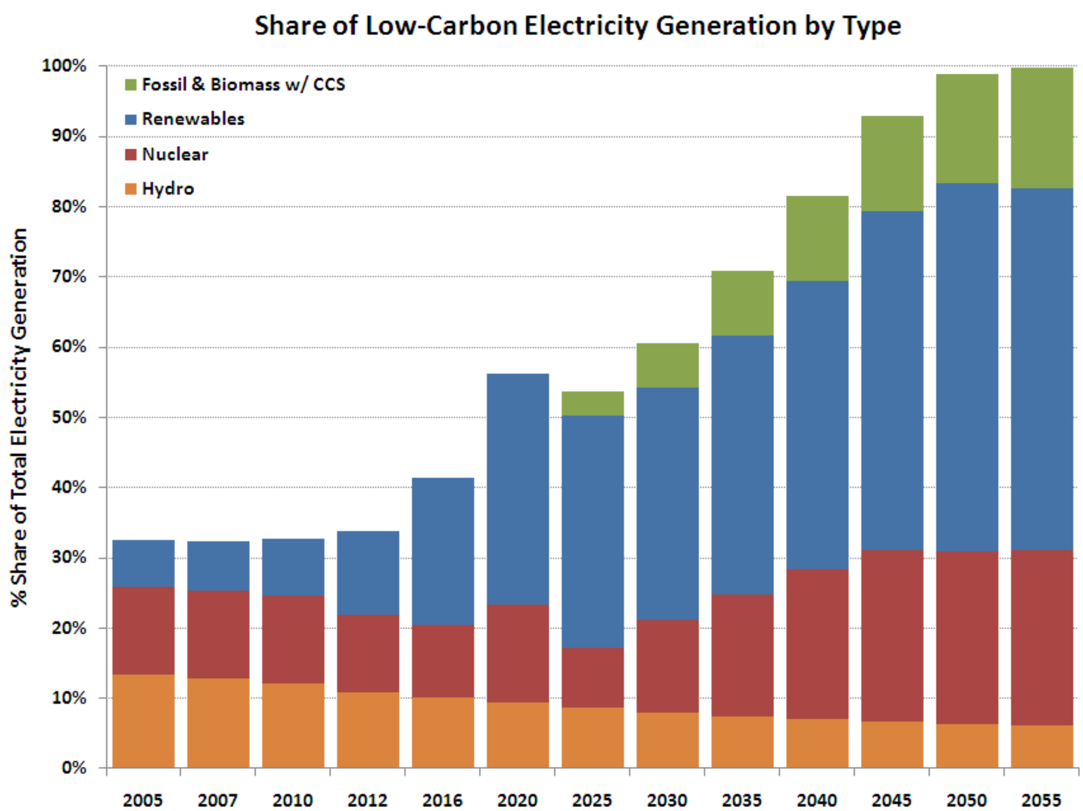


**Figure 55 Share of Low-Carbon Electricity Generation by Type in the Deep GHG Reduction Scenario**

## Energy Supply and Conversion

The mix of fuels supplied by the resource and energy conversion sectors also looks quite different in the Deep GHG Reduction Scenario than in the Reference Case. Most notably, a substantial quantity of liquid fossil fuels is replaced by low-carbon substitutes, such as biofuels, synthetic fuels, electricity, and hydrogen. The types of biofuels consumed are not the same as in the Reference Case, however; for instance, the importance of ethanol declines significantly in the Deep GHG Reduction Scenario (compare Figure 56 with Reference Case Figure 35). Instead, the model chooses to direct biomass to the production of bio-derived gasoline, diesel, jet fuel, and residual fuel oil. The reason for this is fairly intuitive: there are fewer technological/fuel options to reduce GHG emissions in the non-LDV transport subsectors, hence the value of a tonne of biomass is higher when producing a liquid fuel for these other uses. Especially attractive are FT poly-generation plants equipped with CCS and consuming only biomass. In the process of producing zero-carbon bio-based gasoline, diesel, and jet fuel, as well as clean electricity, these technologies function as negative emissions technologies, essentially removing $CO_2$ from the atmosphere and permanently sequestering it underground.

Interestingly, total consumption of biofuels in the Deep GHG Reduction Scenario is at roughly the same level in 2050 (975 PJ or 7.5 billion gge) as it is in the Reference Case. In the latter scenario, the high price of crude oil in a BAU future is enough to motivate substantial biofuels production, while in the former the incentive for biofuels has more to do with the stringent climate targets that are imposed. Total biomass supply (roughly 1,740 PJ, or 108 million bone dry tons) is a bit higher in the Deep GHG Reduction Scenario than in the Reference Case (Figure 57 vs. Reference Case Figure 36), due to the marginally less efficient production methods for producing the non-ethanol biofuels and the attractiveness of generating zero-carbon outputs while at the same time storing $CO_2$ permanently underground. One important difference, however, is just how much more quickly biomass supply grows in the Deep GHG Reduction Scenario, especially between 2025 and 2035, in order to meet the increasingly stringent cap on GHG emissions. Specifically, Herbaceous Energy Crops see greater utilization in the Deep GHG Scenario, despite their higher prices relative to other types of biomass. On the other hand, the model opts for a slower uptake of Mixed Municipal Solid Waste (e.g., foodstuffs and other dirty MSW), which is presumably related to the non-zero carbon intensity of the latter.

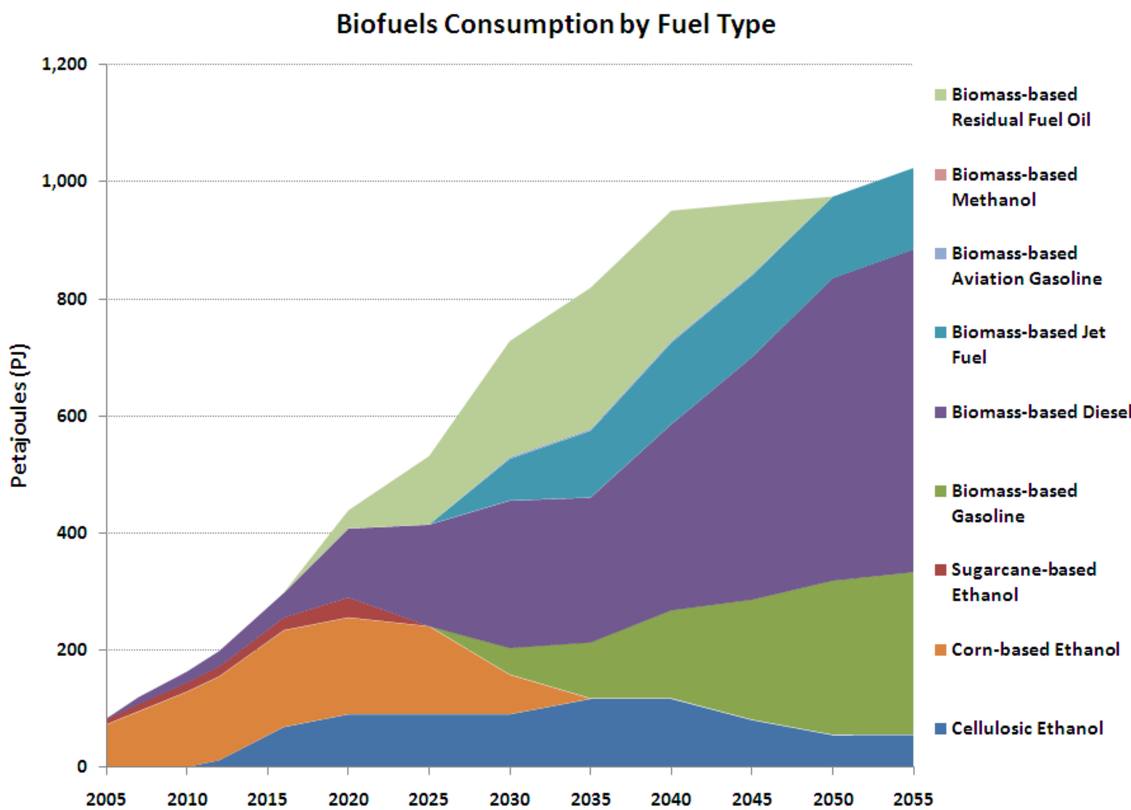


**Figure 56 Biofuels Consumption by Fuel Type in the Deep GHG Reduction Scenario**

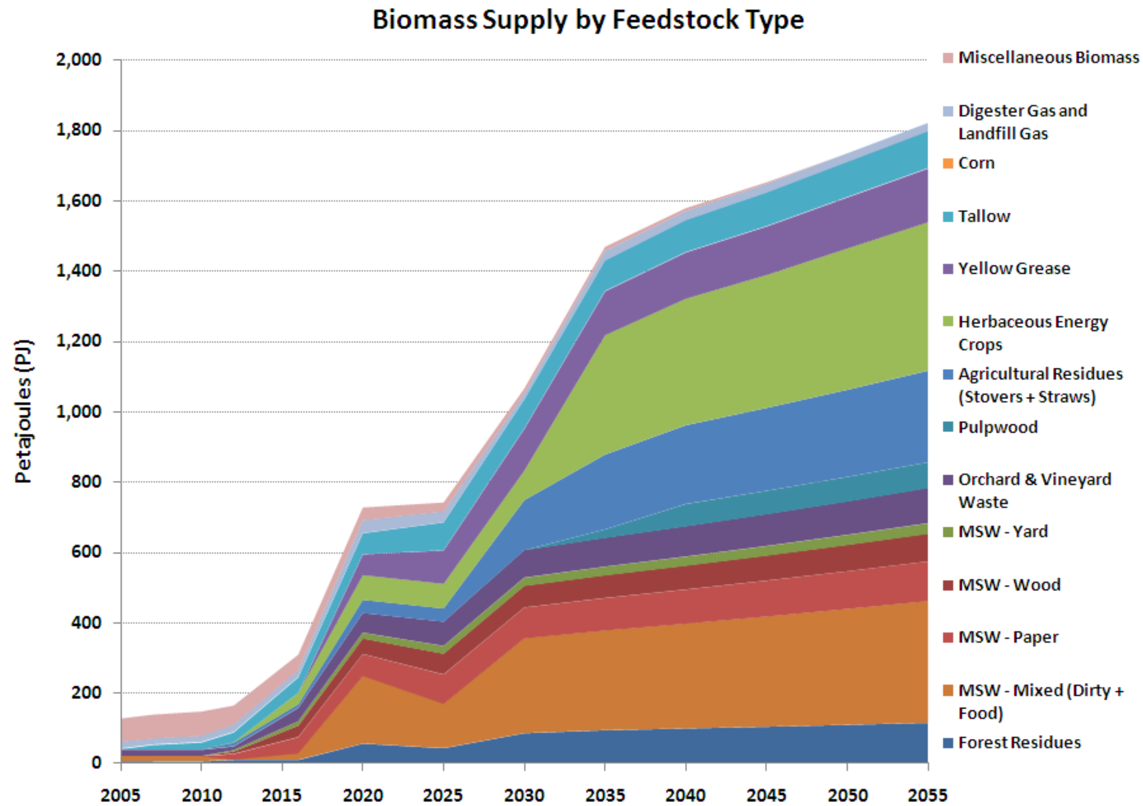


**Figure 57 Biomass Supply by Feedstock Type in the Deep GHG Reduction Scenario**

Hydrogen also becomes an extremely important fuel in the Deep GHG Reduction Scenario, and as Figure 58 illustrates the hydrogen production industry grows quickly after 2030. The preferred method of generation is natural gas steam methane reforming (SMR) with CCS. Water electrolysis and biomass gasification are, in contrast, not cost-competitive under the set of assumptions supplied to the model; hence, they are not used. Moreover, the fact that the model does not opt for biomass-to-$H_2$ plants with CCS – even though this pathway is also a negative emissions option – is particularly noteworthy since it shows the relative attractiveness of converting biomass into liquid fuels via a FT process equipped with CCS, rather than biomass-to-$H_2$. Of course, adding to this attractiveness is the fact that biofuels are in such high demand in certain transport subsectors for which there is no substitute.

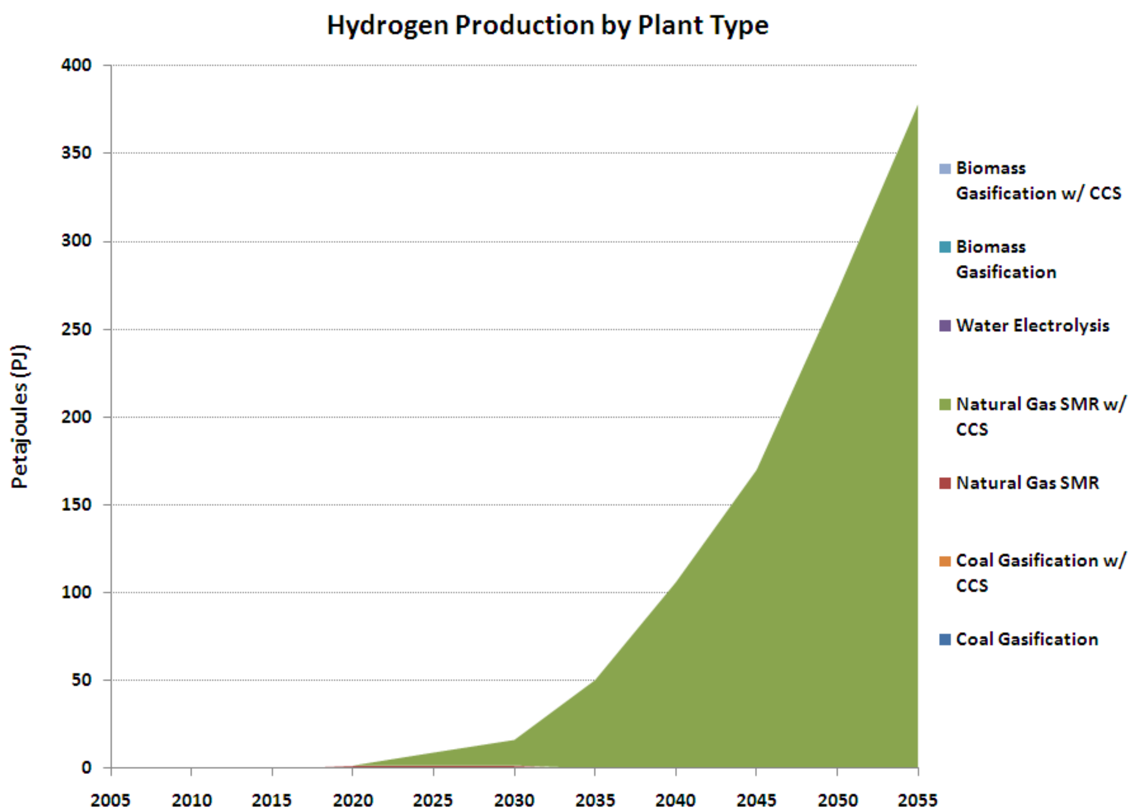


**Figure 58  Hydrogen Production by Plant Type in the Deep GHG Reduction Scenario**

The CCS industry grows quickly after 2025 in the Deep GHG Reduction Scenario (Figure 59), and by 2050 the total quantity of carbon dioxide being stored underground every year is almost twice as much as that being emitted to the atmosphere.  Such high $CO_2$ flows may seem high at first glance, but actually the cumulative quantity of emissions stored until 2055 (~2,930 Mton $CO_2$) is fairly small relative to the overall storage potential that exists in California (~1.5% of total estimated capacity) and the potential in the western U.S. that California energy facilities could possibly have access to (~0.3%), according to mid-range geologic storage estimates from the U.S. DOE National Energy Technology Laboratory's (NETL) *Carbon Sequestration Atlas of the United States and Canada* (NETL, 2008). In other words, CCS is not likely to be limited by storage capacity going forward. The bulk of $CO_2$ capture and storage takes place at natural gas combined-cycle and coal IGCC power plants and FT poly-generation and hydrogen production facilities.

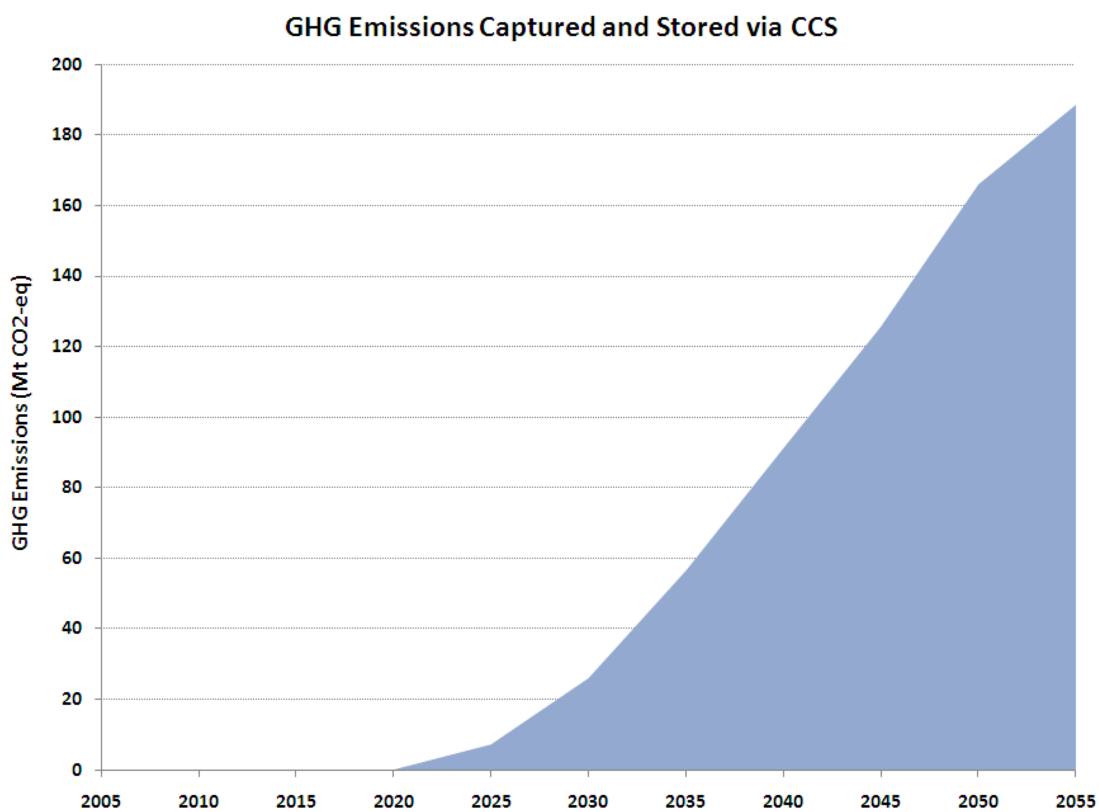


**Figure 59 $CO_2$ Emissions Captured and Stored via CCS in the Deep GHG Reduction Scenario**

## Industrial, Commercial, Residential, and Agricultural Sectors

Treatment of the ICRA sectors – and their exogenously specified trajectories for energy demands and fuel mixes – has already been described earlier in this section. The key points to make note of are two-fold. First, the fuel use mixes of the Deep GHG Reduction Scenario are largely based on the BLUE Map scenario of the IEA. Hence, they are consistent with an overall storyline where California greenhouse gas emissions are reduced 80% below 1990 levels by 2050. Second, the carbon intensities of these sectors are substantially reduced due to a pronounced shift towards what essentially becomes a dual fuel system: electricity is the energy carrier of choice in applications where its use is feasible, and natural gas is utilized for high temperature processes. In addition, a small but non-trivial amount of both biomass (e.g., for industrial boilers) and solar energy (e.g., passive rooftop water heating on buildings) also contributes to the energy supply. The following four figures illustrate the evolution of the ICRA sectors over time in the Deep GHG Reduction Scenario.

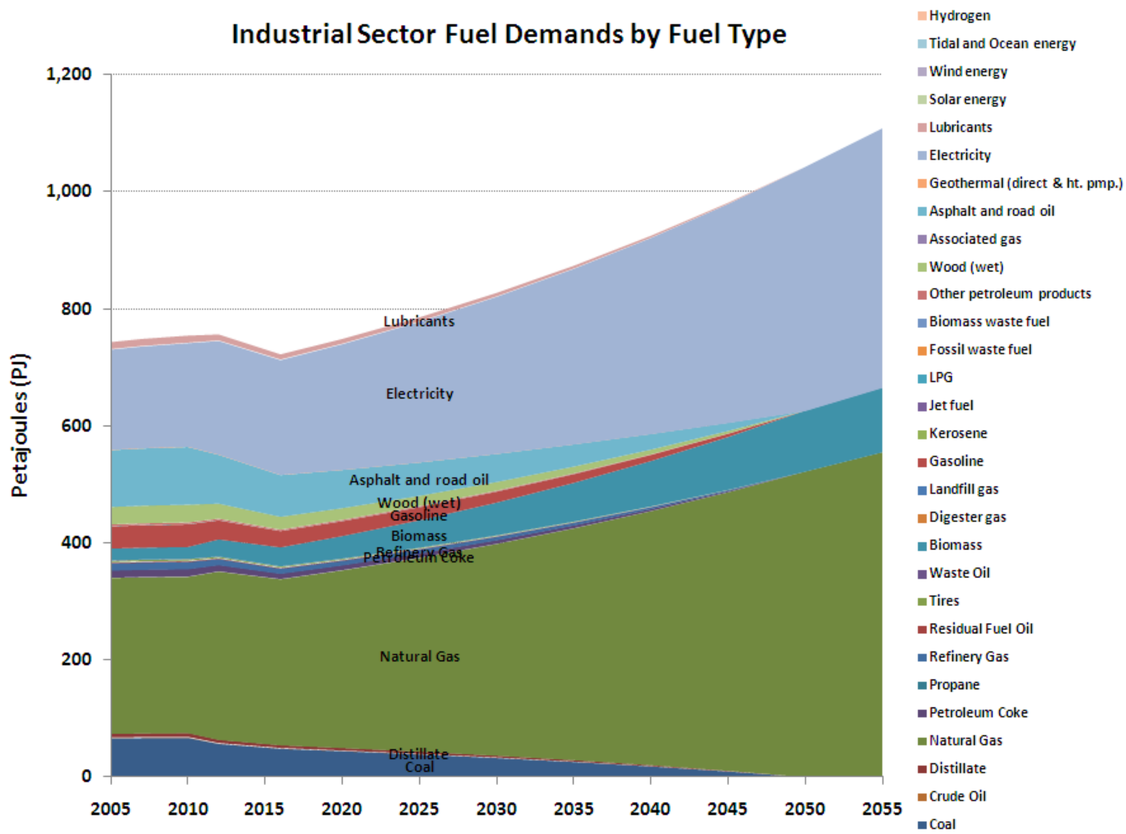


**Figure 60 Useful Energy Demand by Fuel Type in the Industrial Sector in the Deep GHG Reduction Scenario**

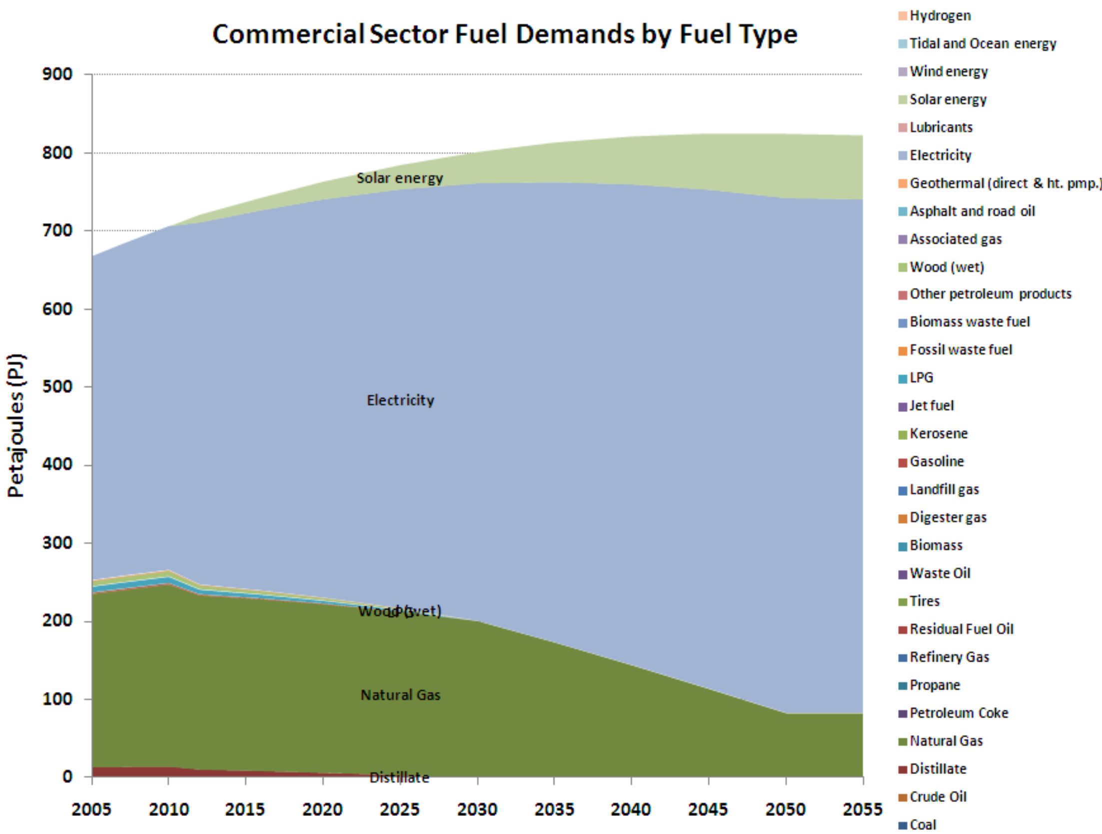


**Figure 61 Useful Energy Demand by Fuel Type in the Commercial Sector in the Deep GHG Reduction Scenario**

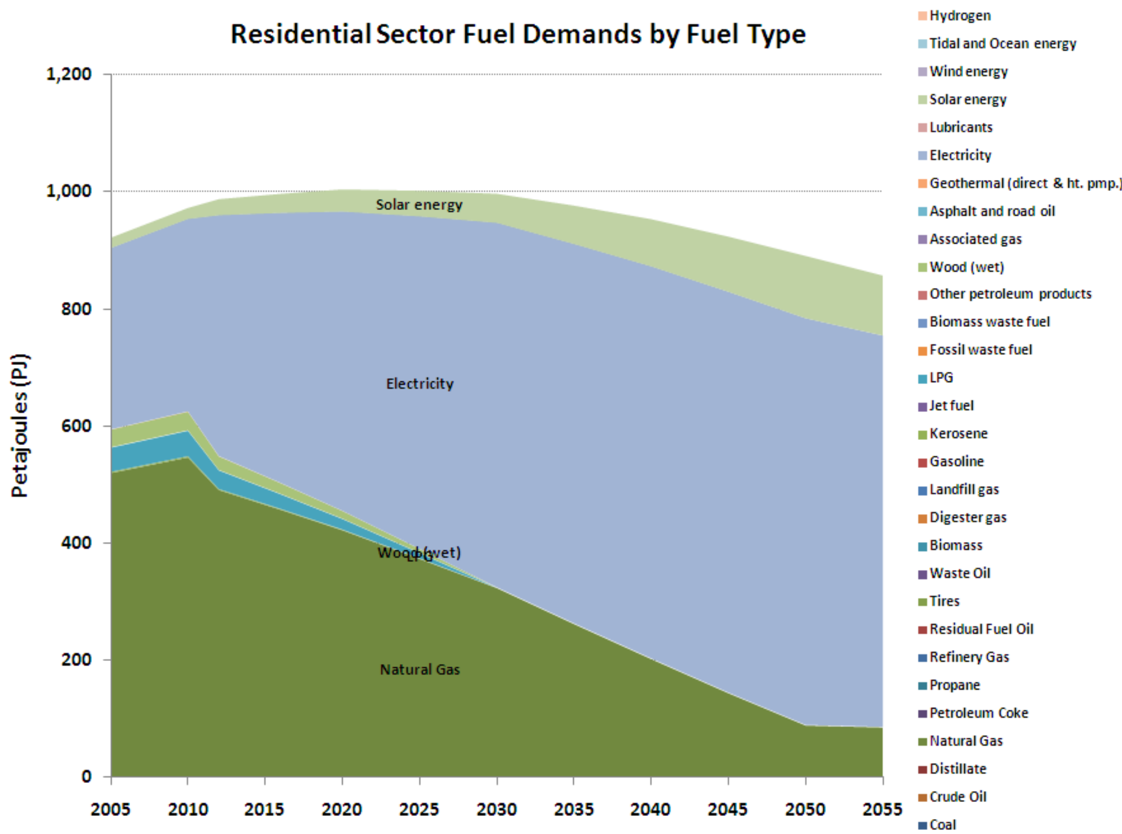


**Figure 62  Useful Energy Demand by Fuel Type in the Residential Sector in the Deep GHG Reduction Scenario**

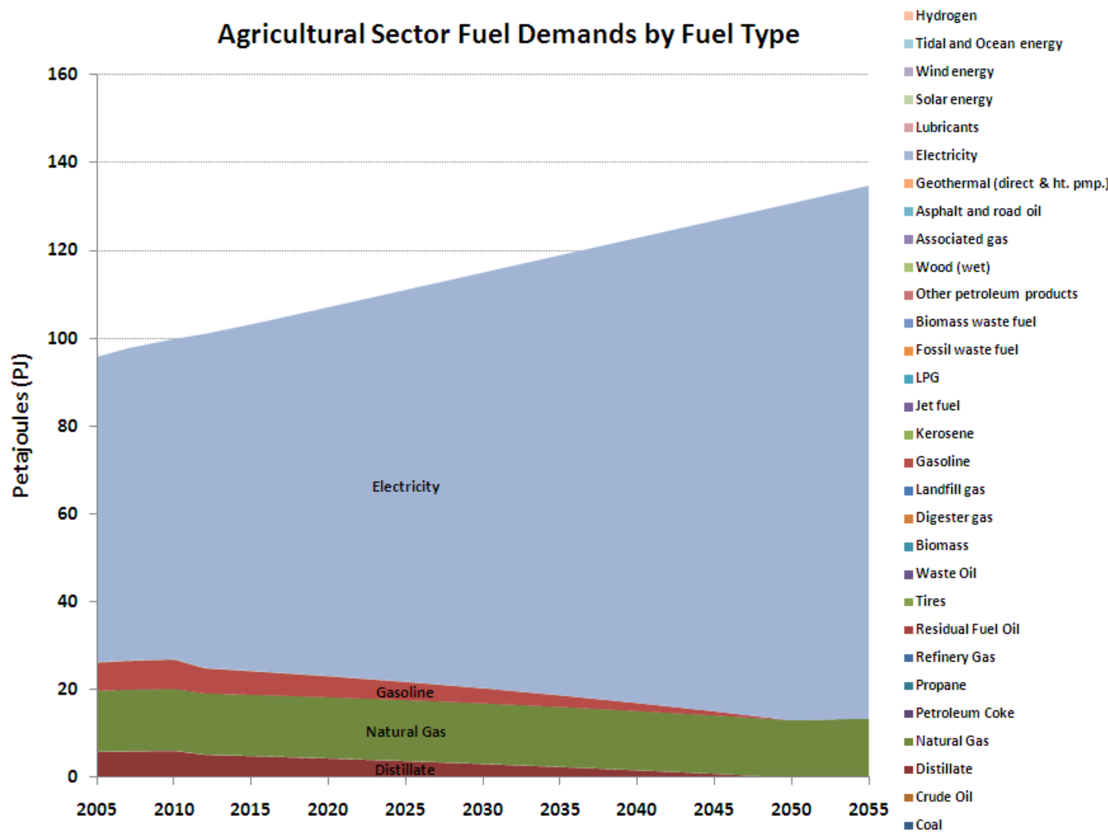


**Figure 63 Useful Energy Demand by Fuel Type in the Agricultural Sector in the Deep GHG Reduction Scenario**

## Transportation Fuels Consumption and Technology Trends

A major transformation also occurs in the transportation sector in the Deep GHG Reduction Scenario. This is illustrated in Figure 64, which shows the mix of fuels consumed sector-wide. The main fossil fuels of today (gasoline, diesel, jet fuel, and residual fuel oil) decline in importance over time: they are still widely used, but their continued upward growth slows down significantly. In contrast ethanol, biodiesel, bio-gasoline, bio-RFO, bio-jet fuel, hydrogen, and electricity all gain market share in the future. Particularly interesting is the small contribution from ethanol in this scenario. In the Reference Case, ethanol (in the form of both E-10 and E-85) grows substantially over the coming decades, once its cost of production becomes competitive with petroleum-based gasoline at high and sustained crude oil prices. In the Deep GHG Reduction Scenario, however, ethanol consumption initially increases (due to the RFS biofuels mandates), but then in the long-run its importance diminishes. The reason for this, as has been discussed previously, is the absence of suitable alternatives for liquid fuels in some of the other transport subsectors and, hence, the higher value of converting biomass to other forms of biofuel (e.g., namely biodiesel, bio-RFO, and bio-jet fuel). An important lesson for policy that derives from these results is the following: while low-carbon ethanol may be an attractive alternative to gasoline over the next 10-20 years, its production may not be the best use of biomass in the long term, assuming deep reductions in GHG emissions need to be made across the all transport subsectors and indeed the entire economy.

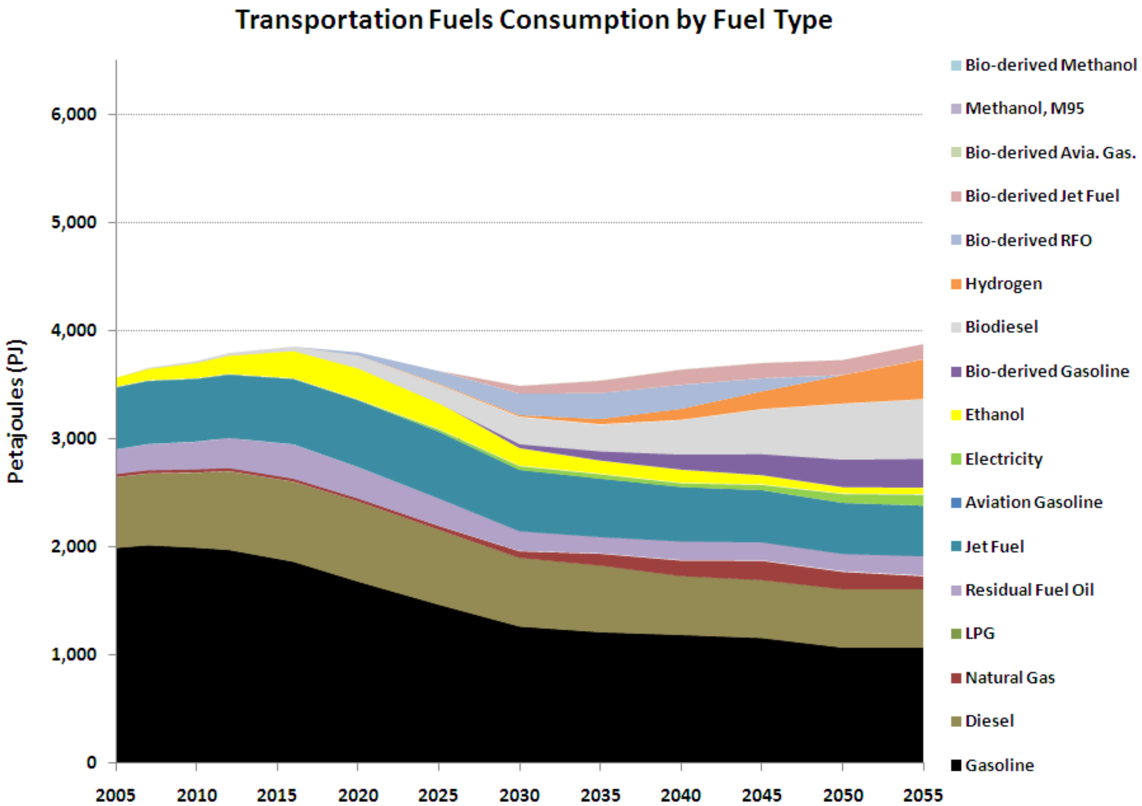


**Figure 64 Final Energy Demand by Fuel Type in the Transportation Sector in the Deep GHG Reduction Scenario**

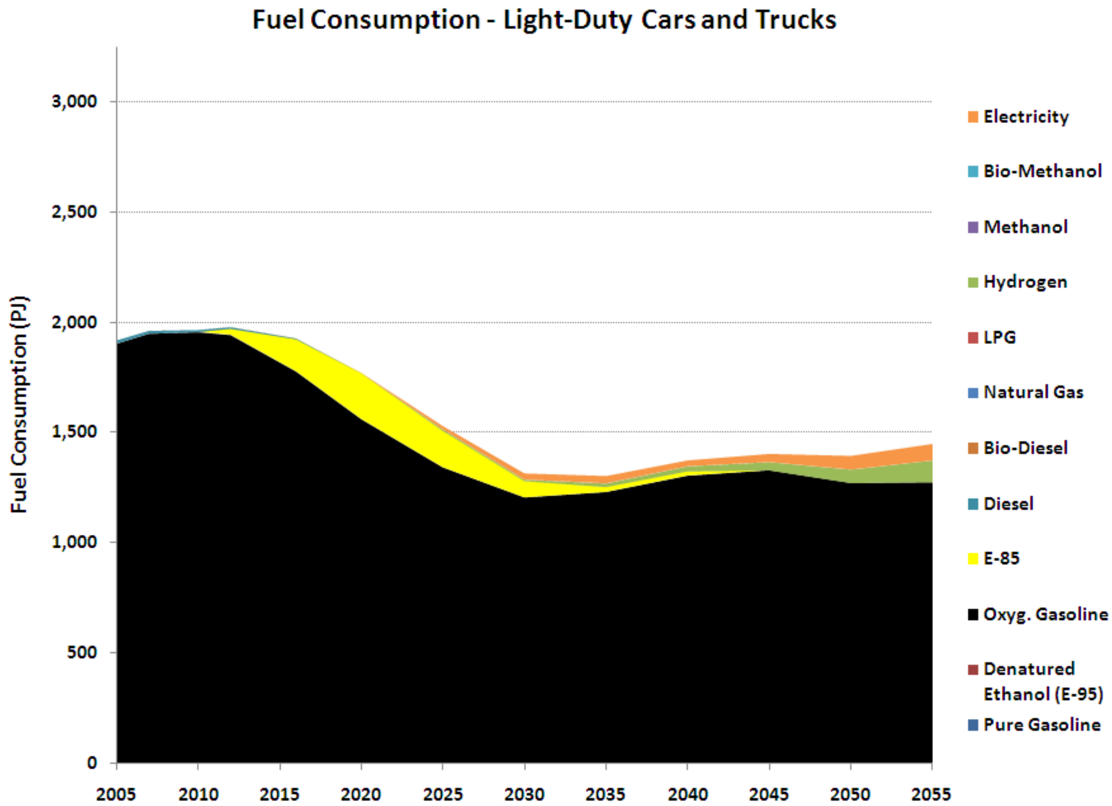


**Figure 65  Fuel Consumption for Light-Duty Vehicles in the Deep GHG Reduction Scenario**

Total transportation fuel consumption in 2050 is cut by about one-third in the Deep GHG Reduction Scenario compared to the same year in the Reference Case, while for light-duty vehicles the reduction is even greater, about one-half (Figure 65).  A portion of this reduction can be attributed to the lower LDV VMT demands assumed in this scenario, which are motivated by strong transit, land use, and auto pricing policies.  The bulk of the reductions, however, are due to greatly increased vehicle efficiencies, made possible by advanced technologies.

The Deep GHG Reduction Scenario sees extensive penetration of advanced vehicle technologies, particularly in the light-duty sector (Figure 66).[49] These actions are motivated by the declining cap on economy-wide GHG emissions, as well as the new, more stringent LDV GHG emissions standards, which are enacted between 2017 and 2025 and gradually raise the minimum fuel economies of new light-duty cars and trucks to 60 mpg and 45 mpgge, respectively, assuming all the GHG reductions are achieved by vehicle efficiency improvements (Figure 67). Standards of such stringency are in line with recent announcements of the U.S. EPA, U.S. DOT, and CARB, who are currently in the process of setting new federal fuel economy and tailpipe emissions standards for model-year 2017-2025 vehicles. In support of this plan, the organizations recently undertook a joint technical assessment to gauge the feasibility of raising vehicle efficiency standards from 3% to 6% per year between 2017 and 2025 (EPA-DOT-CARB, 2010). (The current CAFE standards are set to expire in 2016.) Several scenarios are developed in their analysis, but the main conclusion is that between now and 2025 automakers will need to significantly increase their supply of advanced technology vehicles (namely HEVs, PHEVs, BEVs, and Diesel ICEs) if they hope to meet the more stringent standards. My analysis essentially reaches this same conclusion, as evidenced by the vehicle market share curves shown in Figure 66. The primary difference is that the CA-TIMES Deep GHG Reduction Scenarios also foresees a limited introduction of Hydrogen FCVs by 2025, since the model (with its perfect foresight) recognizes that this low-carbon option must be introduced to the market in the near to medium term, in order for FCVs to have adequate time to build up their capacity by the 2040-2050 timeframe.

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[49] Note that while the main purpose of CA-TIMES is to serve as an energy systems model, it also acts implicitly as a vehicle stock turnover model as well.

Actually, this is true of all advanced vehicle types: subject to constraints on growth, if these technologies are to have enough time to gain significant market share by the middle part of the century, their introduction needs to occur in earnest over the next 10-20 years.

By 2050, the LDV market is dominated by Gasoline HEVs, with Gasoline PHEVs, Hydrogen FCVs, Gasoline ICEs, and E-85 Flex Fuel ICEs and HEVs also playing important roles (Figure 66). Much of the gasoline still consumed by the ICE and PHEV vehicles is petroleum-based, whereas a significant portion (~20%) is either bio-gasoline or synthetic gasoline, both of which are low in carbon and produced by one of the various FT coal-biomass poly-generation plants. Interestingly, battery-electric vehicles do not experience any growth in the Deep GHG Reduction Scenario, an outcome due entirely to the relatively high lifecycle costs of supplying VMT using BEVs, considering both the capital costs of vehicles and their requisite recharging infrastructure (the capital costs for Level I, II, and III charging are all represented in the model). Such a result is indeed questionable given the activity we see around electric vehicles today. However, from the perspective of the CA-TIMES model, one can understand this result by noting that in the model no distinction is made between vehicle classes – i.e., all LDV technologies are represented as mid-size cars. Because mid-size cars weigh significantly more than the types of compact BEVs currently being introduced by automakers around the world, and in order to satisfy consumer demands for vehicle range (200+ miles on a single charge), the battery packs for the light-duty BEVs represented in the CA-TIMES model are actually quite large (~80 kWh). Therefore, total BEV costs are rather expensive relative to other advanced LDV technologies, and partly for this reason we do not see any significant penetration of these vehicles in this very low-carbon future. It is planned that future versions of the CA-TIMES model will allow for greater disaggregation of the various LDV class segments, from compact to mid-size to large cars, and from small to large trucks, minivans, and SUVs. Such market segmentation could potentially lead to greater penetration of BEVs.

The fact that ICE-based drivetrains (including HEVs and PHEVs) continue to make up the bulk of the light-duty vehicle market in 2050 is an interesting result, as it shows the relatively higher abatement costs in this particular transport subsector, not to mention the others. As discussed later, the lack of a dramatic transformation in transport has much to do with the huge emissions reductions that are achieved in the other energy sectors over the next few decades, particularly in the electricity and supply sectors, where zero and even negative emissions are possible, thanks to bio-CCS technologies.

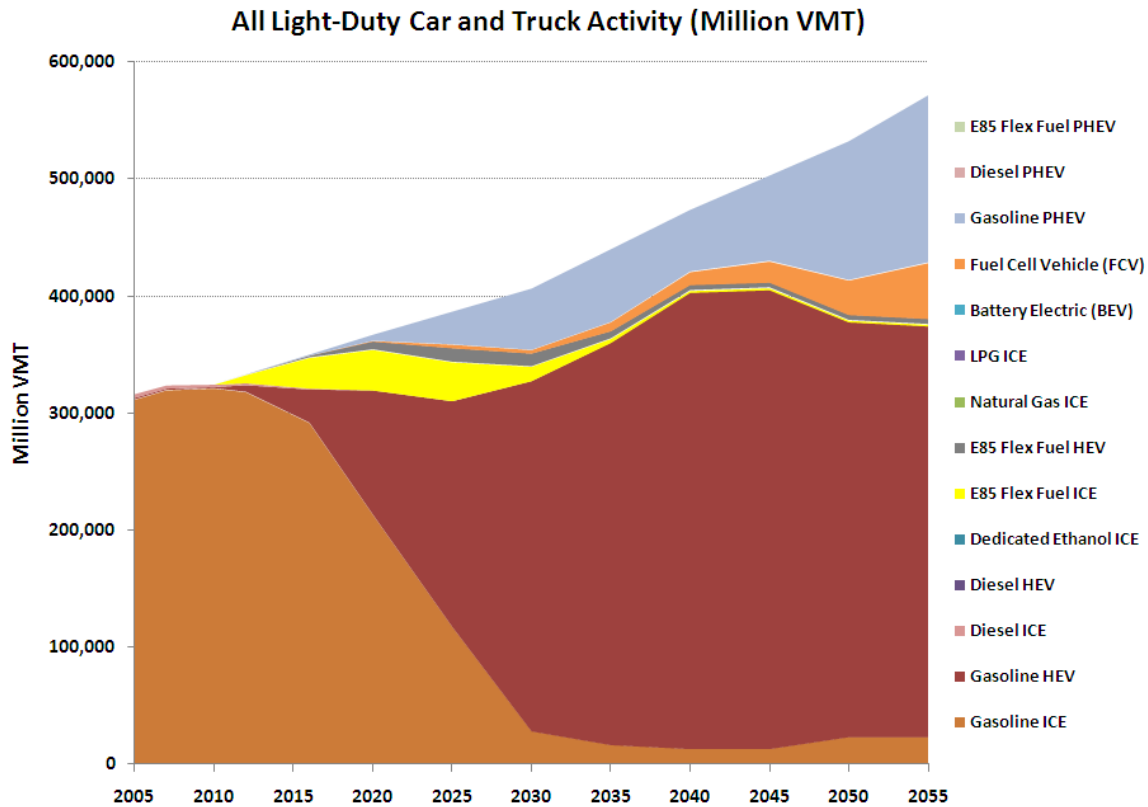


**Figure 66  Technology Penetration in the Light-Duty Vehicle Subsector in the Deep GHG Reduction Scenario**

The average new model-year vehicle fuel economy for light-duty cars and trucks is approximately 66 mpgge in 2050, almost twice the level in the Reference Case and 2.5 times that of today (Figure 67).  Fleet fuel economy (averaging both on-road and new cars and trucks) climbs to 60 mpgge by 2050.  Such high efficiencies lead to the large reductions in LDV fuel demand that are shown in Figure 65.  (Note that the peak in new vehicle fuel economy in 2050 is caused by the so-called “end-year effect”, an artifact of energy-economic systems optimization models that is actually quite common.  In this case, because the required GHG reductions between 2050 and 2055 are quite small, in comparison to the reductions required in the previous five-year intervals, the model –

with its perfect foresight – chooses to invest in cheaper, less efficient vehicles in 2055 than in 2050.)

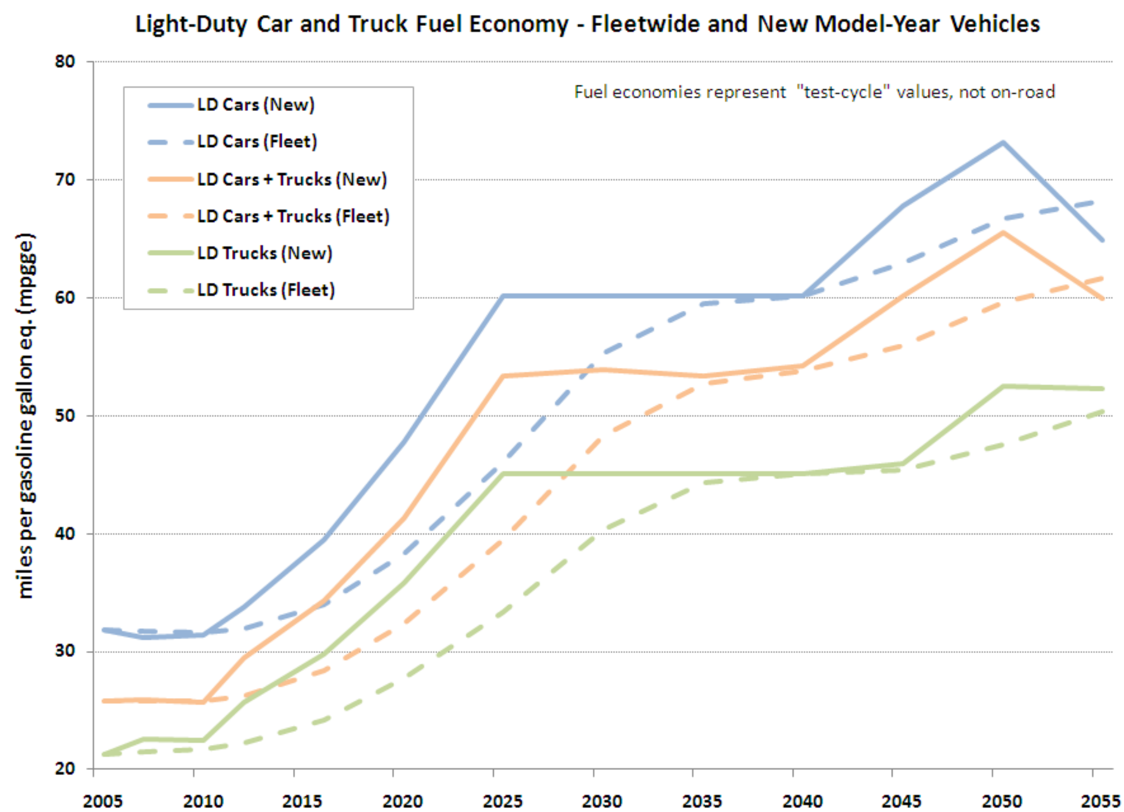


**Figure 67  Average Light-Duty Vehicle Fuel Economy in the Deep GHG Reduction Scenario**

In the non-LDV subsectors, the Deep GHG Reduction Scenario also sees a pronounced shift toward alternative fuels and advanced technologies.  Heavy-duty trucks provide a good example:  total fuel demands are cut significantly as a result of the introduction of high-efficiency Diesel ICE technologies.  (Other advanced technologies, such as PHEVs, BEVs, and FCVs, are not available to the HDT subsector in CA-TIMES, due to range limitations and excessively long refueling times.)  Moreover, the diesel consumed by these vehicles is only partly sourced from conventional petroleum; a large portion comes from low-carbon biodiesel and synthetic diesel.  The Medium-duty Truck and Bus subsectors do not face some of the range and refueling issues associated with long-haul trucks (in fact, a large share of MDTs and Buses are fleet vehicles), hence a greater number of alternative fuel and technology options are available. Accordingly, we see a shift in these subsectors from high-carbon fossil fuels, such as gasoline and diesel, to lower-carbon biodiesel, hydrogen, and natural gas. The model invests in both Hydrogen FCVs and Hydrogen hybrid-electric ICEs in these cases, since both technologies allow for higher efficiencies than Diesel ICEs and both make possible the use of low-carbon hydrogen fuel. In the rail subsector, a portion of Freight Rail operations are electrified by 2050, despite the relatively high capital costs assumed in the model for rail track electrification. Because electrically-powered locomotives are more efficient than conventional diesel or diesel-electric propulsion systems, this technological shift helps to lower total energy demand in the subsector. Emissions reductions in the Marine and Aviation subsectors, on the other hand, are primarily limited to fuel switching, as the options for alternative propulsion systems are more limited. Therefore, the model chooses to direct substantial quantities of bio-derived RFO and bio-jet fuel to these subsectors. Interestingly, Figure 72 shows bio-RFO consumption by marine vessels growing quickly from 2020 to 2035 and then shrinking just as quickly toward 2050. The reason for this seemingly odd behavior has to do with the lack of CCS-capability (and thus negative emissions potential) with the pyrolysis bio-oil production pathway used for making bio-RFO. The model prefers instead to direct limited biomass supplies to the FT poly-generation plants, which produce bio-based gasoline, diesel, and jet fuel, as well as electricity, while at the same time sequestering a significant portion of the biomass carbon permanently underground.

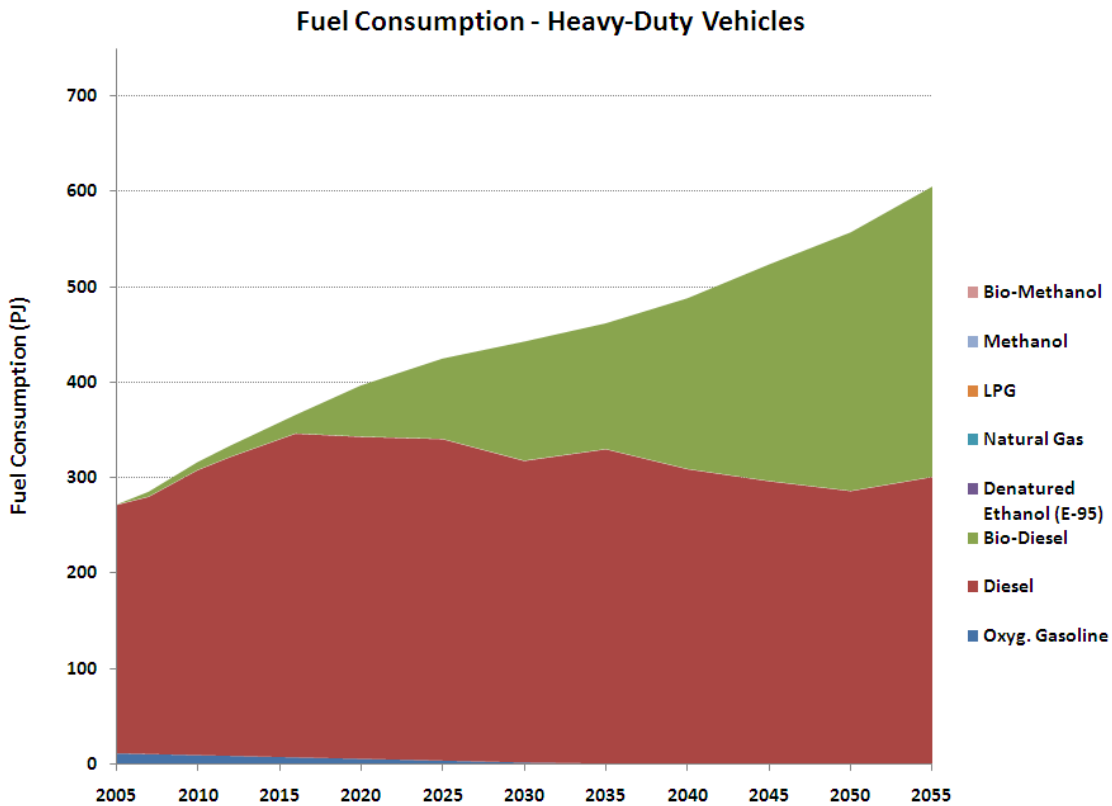


**Figure 68 Fuel Consumption for Heavy-Duty Trucks in the Deep GHG Reduction Scenario**

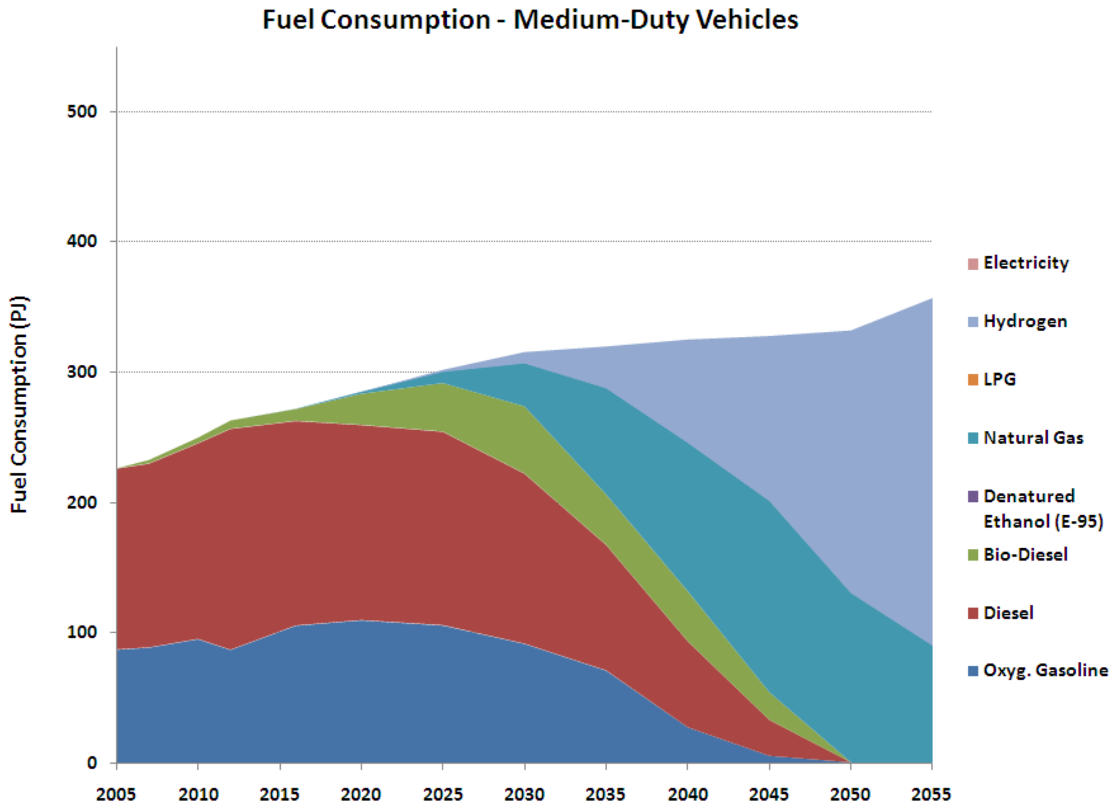


**Figure 69 Fuel Consumption for Medium-Duty Trucks in the Deep GHG Reduction Scenario**

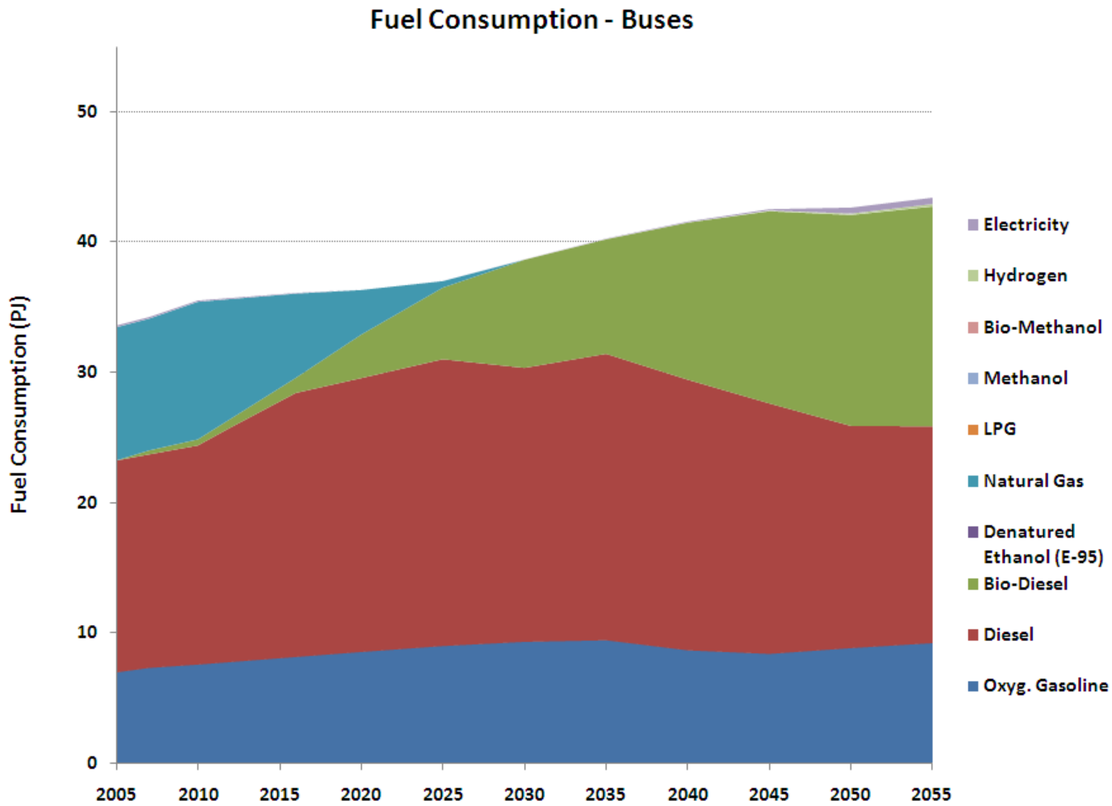


**Figure 70  Fuel Consumption for Buses in the Deep GHG Reduction Scenario**

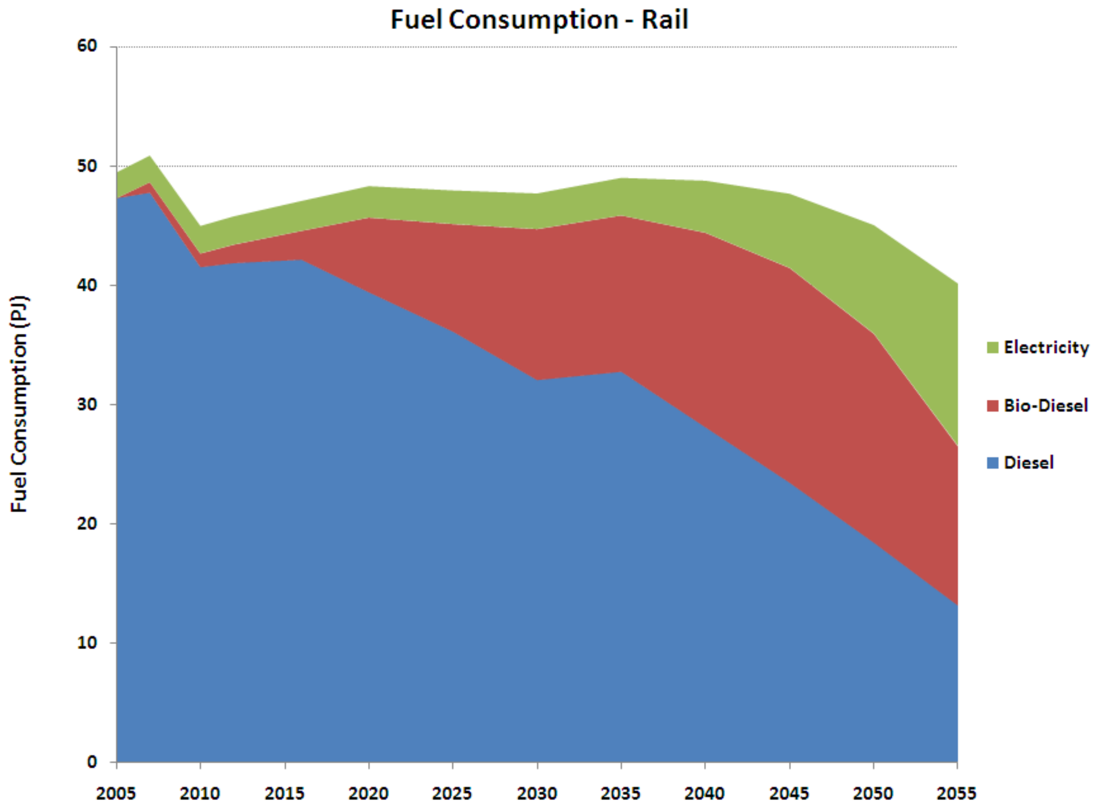


**Figure 71  Fuel Consumption for Rail in the Deep GHG Reduction Scenario**

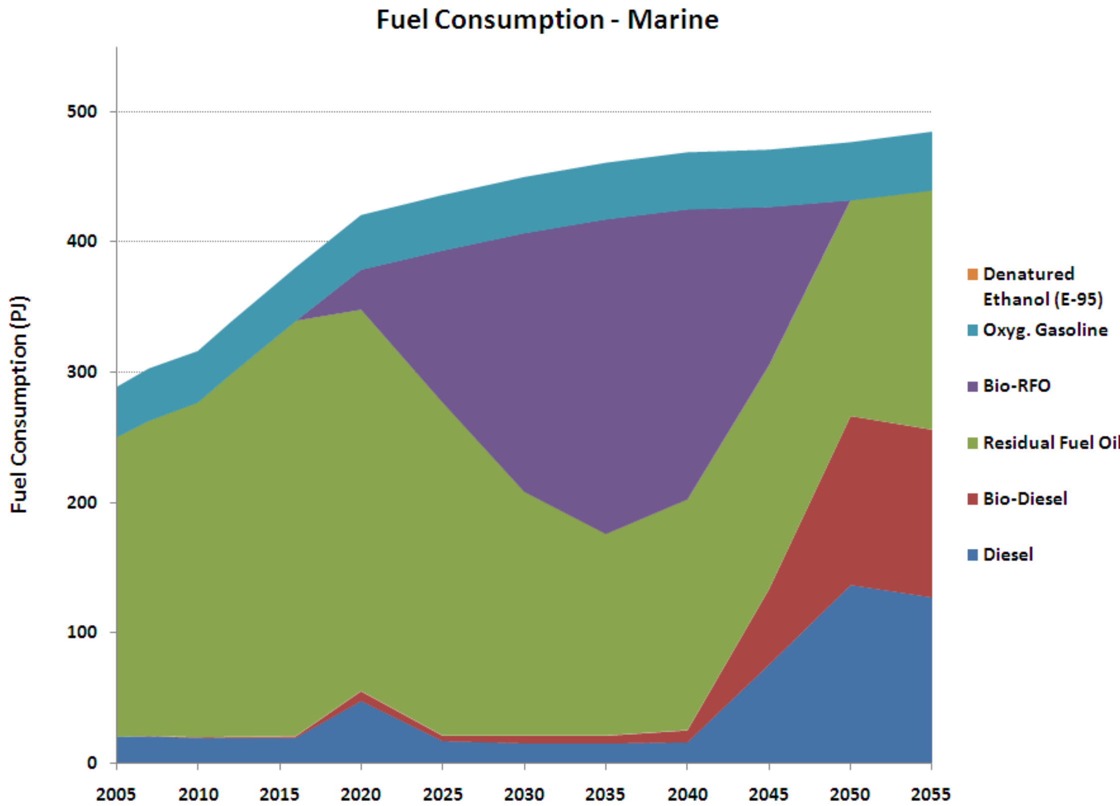


**Figure 72 Fuel Consumption for Marine Vessels in the Deep GHG Reduction Scenario**

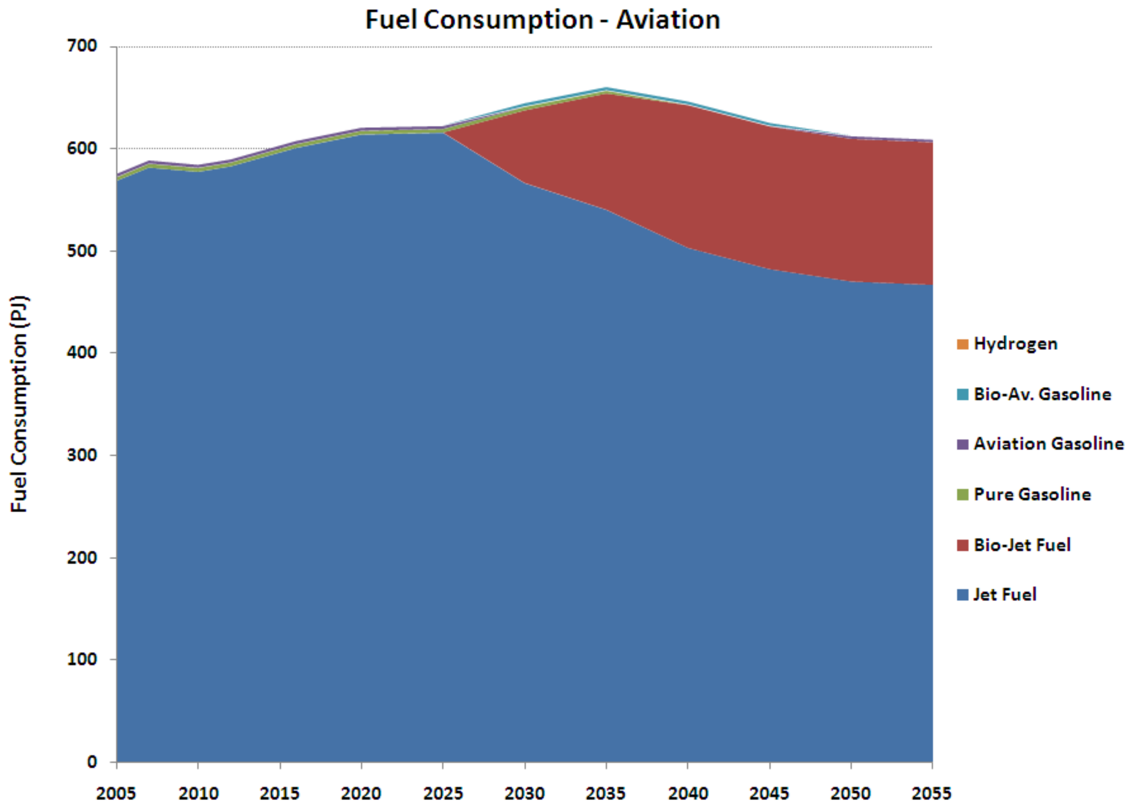


**Figure 73 Fuel Consumption for Aviation in the Deep GHG Reduction Scenario**

## Greenhouse Gas Emissions

By transitioning to an energy system that relies more heavily on advanced technologies and alternative fuels, the potential exists for substantial reductions in greenhouse gas emissions in California in the long term. Figure 74 shows CA-TIMES model estimates of annual GHG emissions produced via fuel combustion activities in each of the state's various energy sectors. Figure 75 is similar except that emissions from electric generation are allocated to end-uses. Note that a straight line declining cap on emissions is assumed in the scenario, which helps to explain the shape of the emissions trajectory shown here.[50] Otherwise, if the model were free to set its own schedule for emission reductions (as estimated in a side analysis, the results for which are not shown here), it would choose to push the deepest cuts to the later time periods (i.e., after 2040), in response to the non-zero global discount rates used in the model, which essentially make long-term costs less important than near- to medium-term costs in the calculation of total discounted system costs on a net present value basis.[51] While postponing mitigation actions may make sense from the point of view of the model, it is probably not reflective of the real world, in which policymakers of the future are likely set interim emission targets between 2020 and 2050, in order to ensure that the system is on track to meet the long-term deep reduction goals (as well as to further the achievement of various other political objectives, such as job creation).

A particularly noteworthy finding relates to the GHG emissions target for 2020 (i.e., the AB32 goal of returning to 1990 levels by this year). Even though a cap is set for 2020, the model actually opts to undershoot the limit (i.e., the constraint is non-binding), in order to prepare for the following time period just five years later, when the emissions cap is lower still. What this says is that, according to the multitude of assumptions made in this particular scenario, for the California energy system to put itself on track to reach the deep reduction targets of the long term (80% by 2050), while following a linearly declining emissions trajectory, GHG emissions in 2020 will likely need to be lower than

[50] Other modeling groups in the U.S. and abroad tend to represent declining emission caps by the same straight line trajectory approach that I have used, as noted through my interactions with the North American MARKAL-TIMES users group and the Stanford-based Energy Modeling Forum.

[51] In such a case, the primary limiting factors that would militate against such an outcome (i.e., pushing GHG emissions reductions to the very last period) are the growth constraints assumed in the model, which force the investment in and utilization of advanced technologies and alternative fuels in the near- and medium-term, so that there is enough time for them to gain significant market share by 2050.

the cap currently specified by AB32. In other words, while returning to 1990 emission levels by 2020 will certainly represent a big achievement for California, from a long-term perspective such a target may not be stringent enough.

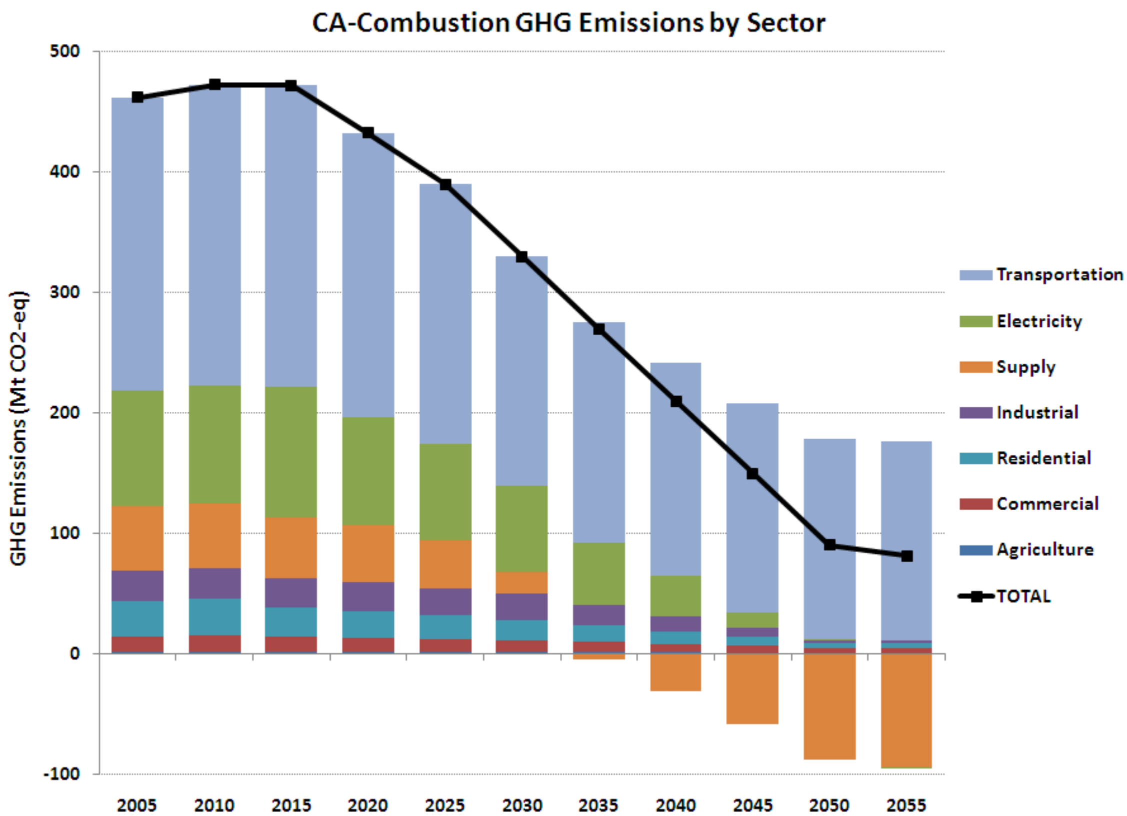


**Figure 74** ***CA-Combustion*** **GHG Emissions by Sector in the Deep GHG Reduction Scenario**

Two other striking observations from the GHG emissions figures shown here relate to the dominance of transport sector emissions in the long term and the huge potential for negative emissions in the supply sector. Both of these findings are intimately related to each other, since the types of technologies that are able to permanently sequester biomass carbon underground (i.e., FT poly-generation plants) are the same ones that supply the transport sector with biomass-based gasoline, diesel, and jet fuel. Because of the considerable potential for bio-CCS, the other sectors are allowed to emit more than they otherwise would be able to, if negative emissions technologies were not available. In other words, these other sectors are not forced to reduce their emissions so stringently. The transportation sector is the primary benefactor in such a circumstance, given that marginal $CO_2$ abatement costs are generally higher in transport than in other sectors. (Another reason is the exogenously specified scenario storyline assumed for the industrial, commercial, residential, and agricultural sectors.) For instance, while supply sector emissions are reduced 262% between 2005 and 2050 (and in the electric sector by 99%), emissions in transport decrease by only 32%. Such findings are in line with other modeling studies (e.g., IEA (2010)), which show that from a cost-perspective and in the absence of any transport-specific GHG policies, certain segments of the transport sector are likely to be the last to decarbonize. The unique contribution of this study, at least within the California context, is that it highlights the enormous potential for bio-CCS negative emissions technologies and the critical role they may be able to play in controlling GHG emissions in the state, as well as taking the load off some of the other sectors, especially transport. Of course, this line of reasoning is contingent upon the eventual success and public acceptance of these technologies, as well as the ultimate size of the sustainable biomass feedstock base available to California. If bio-CCS technologies are constrained for any of these reasons in the future, then the potential for negative emissions in California would be significantly hindered, and the transportation sector would indeed be required to reduce its emissions by a considerably larger amount. These kind of sensitivities are explored in later sections of this chapter, wherein a handful of interesting variants of the Deep GHG Reduction Scenario are analyzed.

At first glance, the results discussed here might seem to contradict those shown in the first chapter of this dissertation, which looked at the potential for making 80% cuts in (well-to-wheel) greenhouse gas emissions in the U.S. transport sector by 2050 (alsoYang, McCollum et al. (2009), who studied similar scenarios for California). That analysis highlighted the critical role that advanced vehicle technologies and alternative fuels would perhaps need to play in the long term. The question raised by the analysis was whether or not the transport sector would ever actually need to achieve an 80% reduction on its own, or could emissions reductions be made more cost-effectively in other sectors. The CA-TIMES work discussed here was developed for the express purpose of addressing these kinds of questions, and the findings that derive from the analysis are very interesting. Namely, emissions reductions in the transport sector may not actually need to be as large as that assumed in the 80in50 study of Chapter I; in fact, they may not need to be anywhere near as great, so long as the potential for negative emissions technologies exists on the supply side.

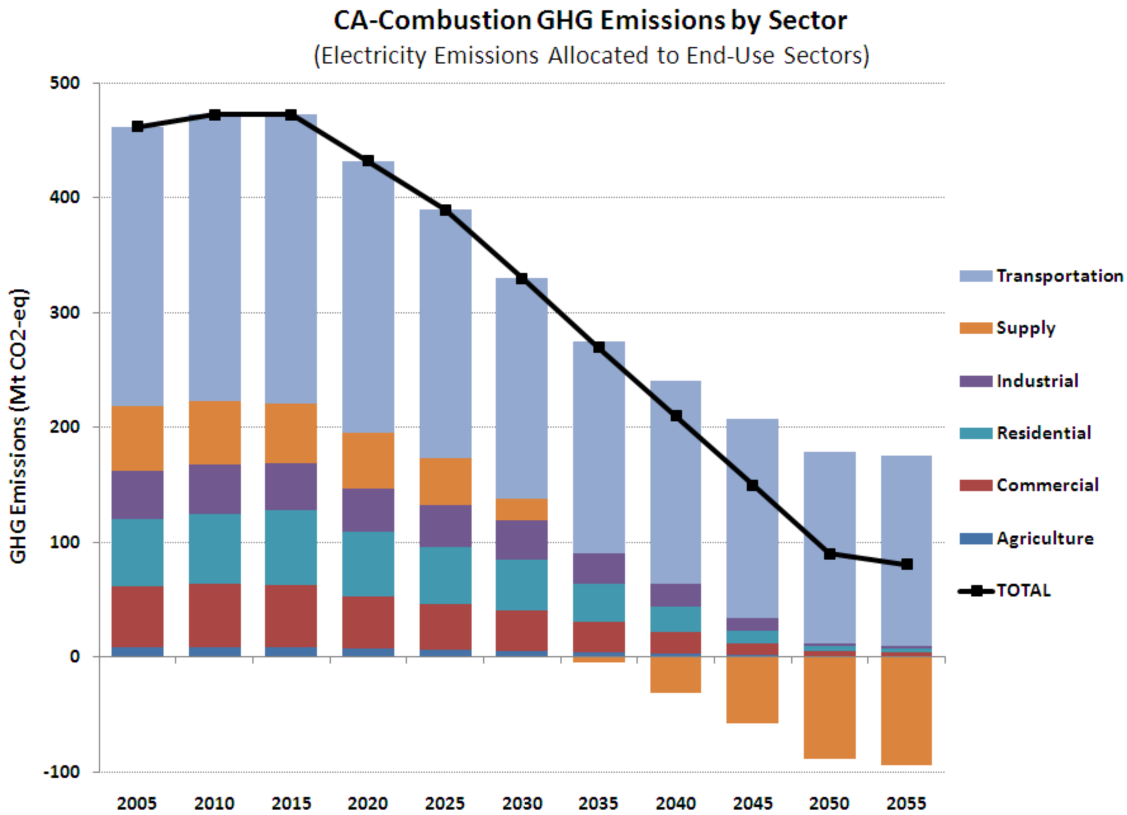


**Figure 75** ***CA-Combustion*** **GHG Emissions by Sector in the Deep GHG Reduction Scenario with Electricity Emissions Allocated to the Various End-Use Sectors**

The cumulative quantity of GHGs emitted between 2005 and 2055 (i.e., the area under the total emissions curve in Figure 74) is approximately 15,762 Mton $CO_2$-eq in the Deep GHG Reduction Scenario. Over the more limited period of 2012 to 2050, cumulative emissions are just 12,048 Mton $CO_2$-eq. By comparison, cumulative emissions in the Reference Case are a much higher 27,552 and 21,140 Mton $CO_2$-eq, respectively, over these two timeframes. The period between 2012 and 2050 is particularly relevant because of the U.S. National Research Council's recent recommendation that total domestic U.S. greenhouse gases from all sources (both fuel combustion and non-energy GHGs) stay within a cumulative emissions "budget" of 170,000 to 200,000 Mton $CO_2$-eq during this timeframe (NRC, 2010). Such a budget corresponds to reductions in annual

GHG emissions by 2050 that are between 80% and 50% below 1990 levels, respectively, at the national level. In the Deep GHG Reduction Scenario developed here (an 80% reduction scenario), California's cumulative emissions, which one should be reminded only include fuel combustion, represent about 7.1% of this national emissions budget, which is only slightly less than the state's current contribution to total domestic U.S. GHGs. (The small discrepancy is understandable when considering that only fuel combustion emissions are captured by CA-TIMES.) For illustrative purposes, if we assume that this 7.1% figure is roughly representative of California's "fair share" of U.S. GHGs, then California's emissions budget over the 2012 to 2050 time period is estimated at 12,100 and 14,200 Mton $CO_2$-eq, respectively, depending on the stringency of the 2050 emissions target (80% or 50%). While the Deep GHG Reduction Scenario remains within these budgets, the Reference Case far exceeds it. In fact, if California continues to follow a business-as-usual Reference Case scenario for energy system development, then its emissions budget is likely to be exceeded well before 2050. Instead, the budget would probably be exceeded around 2035.

The average "well-to-wheel" lifecycle carbon intensity (including both upstream/ "well-to-tank" and downstream/"tank-to-wheel" stages) of all fuels consumed in the transportation sector decreases from 82.8 $gCO_2$-eq/$MJ_{HHV}$ in 2005 to 31.1 $gCO_2$-eq/$MJ_{HHV}$ in 2050, a difference of about 62% (Figure 76). (Remember that because these carbon intensities are calculated on a HHV basis, they are about 7 to 11% lower than if calculated on a LHV basis.) In the LDV subsector, the drop is not quite as large, with average carbon intensity declining to just 44.8 $gCO_2$-eq/$MJ_{HHV}$ in 2050 (Figure 77). In other words, fuel carbon intensities are lower, on average, in the non-LDV subsectors, thanks to a larger amount of fuel switching.  Emissions reductions made during the well-to-tank stages of fuel production are the primary driver of lower total lifecycle carbon intensities.  In particular, the fact that well-to-tank emissions eventually become negative has everything to do with the increased utilization of biomass-based gasoline, diesel, and jet fuel, which are produced by bio-CCS negative emissions technologies, as previous discussions in this section have made all too clear.  During the tank-to-wheel stage (i.e., fuel combustion), greater consumption of low- and zero-carbon biofuels and electricity, as well as hydrogen in certain transport subsectors, is responsible for the declines that result.

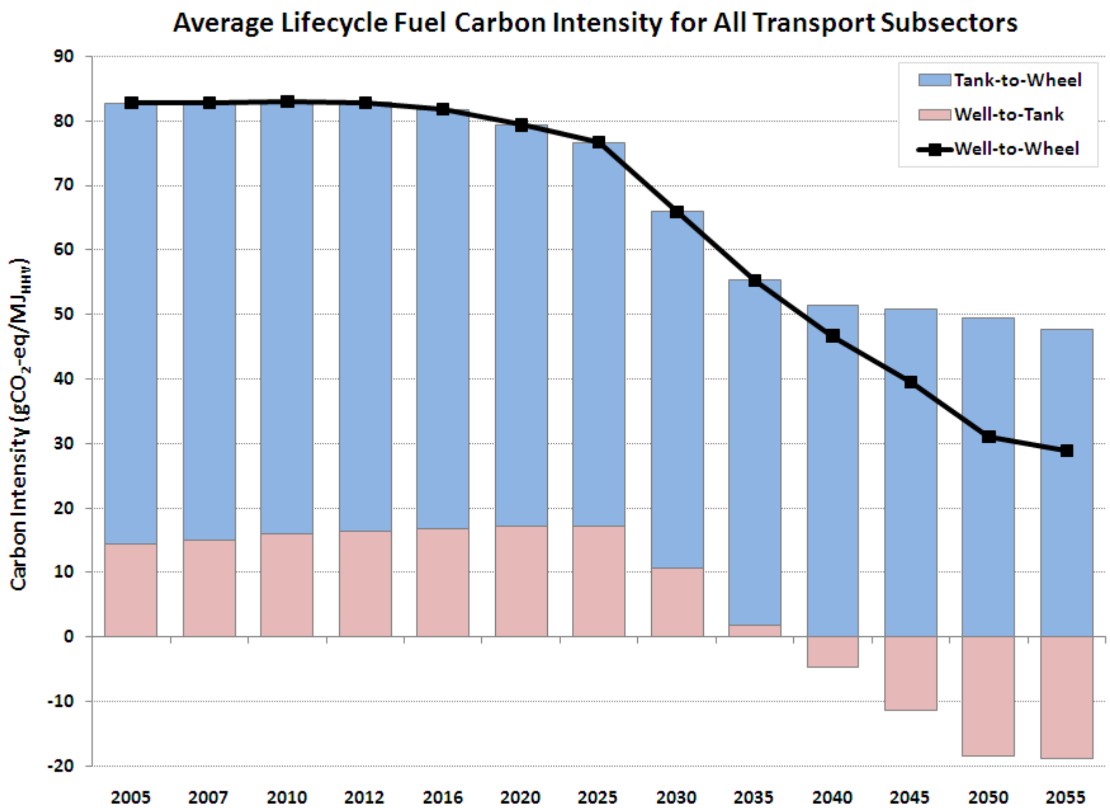


**Figure 76 Average Lifecycle Carbon Intensity of All Fuels Consumed in the Transportation Sector in the Deep GHG Reduction Scenario**

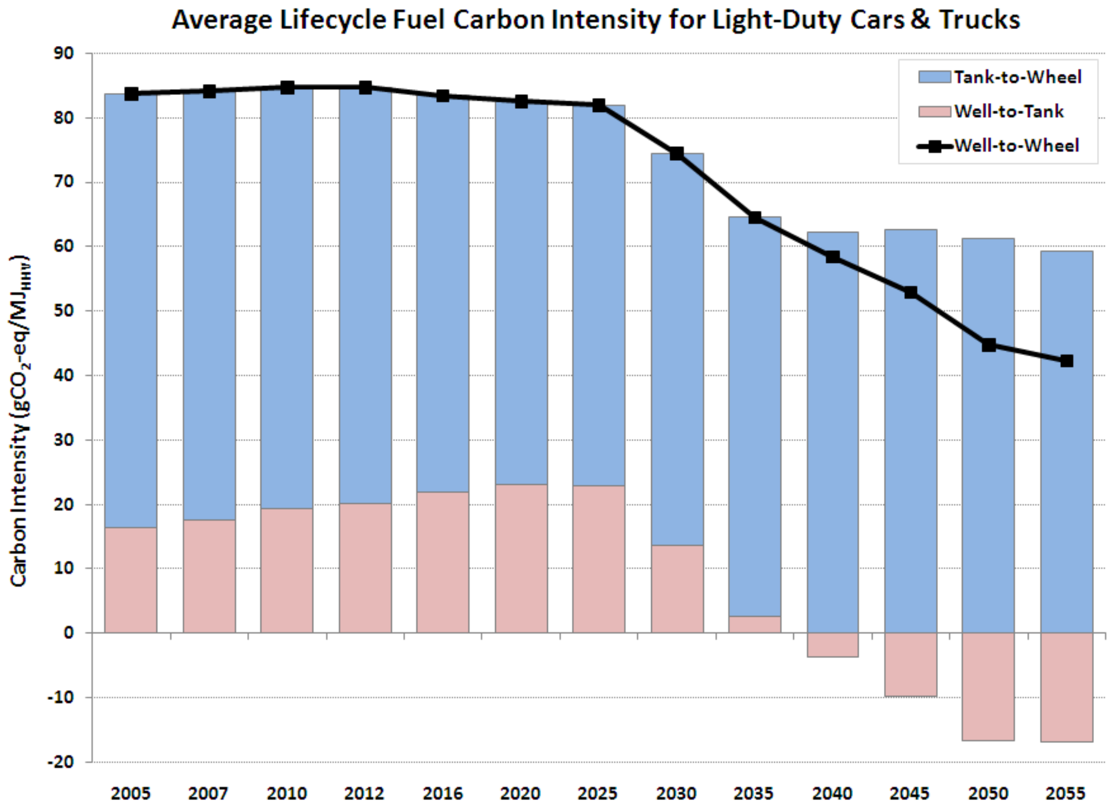


**Figure 77  Average Lifecycle Carbon Intensity of All Fuels Consumed in the Light-Duty Vehicle Subsector in the Deep GHG Reduction Scenario**

### *II.3.3   Deep GHG Reduction Scenario Variants*

Up to this point in the chapter, two core scenarios have been thoroughly discussed – the Reference Case and Deep GHG Reduction Scenario.  Each represents a potential path for the development of California's energy system over the coming decades.  A considerable amount of time and effort has gone into creating these scenarios, but at the end of the day they are just two out of an infinite number of possible eventualities.  And while both paths are thought to be feasible from a technological perspective, in the sense that both were developed based on reasonable assumptions from the literature, neither should be taken as a definitive prediction of how events will unfold in the coming years.  Herein lies one of the most delicate elements of "what-if"-type scenario analyses: because no single scenario offers an absolutely certain picture of the future, it is up to the modeler to develop alternate scenarios and to undertake sensitivity analyses around key assumptions. The challenge, of course, centers around where to focus one's attention, given that scenarios of the type developed using energy systems models, such as CA-TIMES, are built on thousands, or even tens of thousands, of assumptions.

In this section, several variants of the Deep GHG Reduction Scenario are developed. In the first exercise, I maintain all previous assumptions, while changing the most important policy driver: the stringency of the cap on GHG emissions. Then, in a second exercise the Deep GHG Reduction Scenario is modified much more extensively: specifically, assumptions concerning the potential of certain key low-carbon technologies and resources are significantly altered (generally resulting in less technological optimism). The scenario variants are compared across a range of energy, environmental, and cost metrics.

*Scenario Variants #1: Modification of the GHG Emissions Cap*

The most important driver of energy system development in the core Deep GHG Reduction Scenario is the declining cap on GHG emissions, which ultimately reaches 80% below 1990 emissions levels by 2050. A climate target of such stringency leads to dramatic shifts in the types of technologies and fuels utilized in California in the future, as shown in previous sections. Due to its importance, an obvious question thus becomes, "How might the situation change if the emissions cap were less stringent?" Perhaps policymakers decide next year, or in ten years from now, to scale back their aspirations for achieving the 80% reduction target, opting instead for something less stringent. Or perhaps the science surrounding climate change evolves in such a way that suggests an 80% cut in California (as well as U.S. and other industrialized country) emissions is not actually necessary. (Of course, the alternate outcome is equally as likely, that even deeper cuts in emissions are needed.) In an effort to address this question, I develop three additional scenarios, in which the cap on GHG emissions is set at 50%, 60%, and 70% below 1990 levels by 2050. For each scenario, the trajectory of the cap is assumed to decline linearly from the same 2020 starting point as in the original Deep GHG Reduction Scenario (i.e., the 1990 level).

Other than the modified emission targets, all other assumptions in these scenario variants are the same as in the core Deep GHG Reduction Scenario. This includes the exogenous fossil fuel price projections and the exogenously specified fuel demands in the ICRA sectors, both of which, it should be reminded, were developed with an 80% reduction scenario in mind. With respect to the ICRA sectors in particular, by keeping their fuel mixes the same, the introduction of climate caps with reduced stringencies effectively means that the transport, electricity, and supply sectors do not have to reduce their emissions quite as much. This potentially injects some error into these scenarios, since it is unlikely that exactly the same technologies and fuels would be used in the ICRA sectors in an 80% reduction scenario as would be in a 50% scenario. However, in any event I have decided not to explicitly address the issue for now, given that my analysis focuses on the transport, electricity, and supply sectors and the advanced technologies and alternative fuels utilized therein.

In addition to the three scenario variants with alternative caps on GHG emissions, I also develop a scenario that is a variant of the Reference Case. The only differences between the original Reference Case and its variant are the demands exogenously assumed in the end-use sectors. More specifically, the lower demands of the Deep GHG Reduction Scenario are used; hence, this scenario variant is named "Reference Case (w/ Lower Demands)". Otherwise, all technological assumptions are the same as in the original Reference Case – fossil fuel price projections, the exogenously specified fuel demands of the ICRA end-use sectors, and so on. The reason for developing this scenario variant is that, as evidenced in the discussions that follow, demand reduction apparently has a fairly substantial impact on energy use, greenhouse gas emissions, and costs. Therefore, in analyzing the Deep GHG Reduction Scenario variants across the range of energy, environmental, and cost metrics, it seems only fair to compare them to the Reference Case (w/ Lower Demands), since the policies leading to the assumed demand reductions in these scenarios (e.g., strong transit, land use, and auto pricing policies in the transport sector, and energy efficiency standards in the industrial, commercial, residential, and agricultural sectors) are not adequately captured by the CA-TIMES model.

Figure 78 compares the GHG emissions trajectories of the Reference Case, Reference Case (w/ Lower Demands), Deep GHG Reduction Scenario, and the three Deep GHG variants. As a result of demand reduction, GHG emissions in 2050 are 125 Mton lower in the Reference Case (w/ Lower Demands) than in the original Reference Case. All other emissions cuts can be classified as technological reductions, in the sense that they result from switching to lower-carbon fuels and the introduction of advanced, more efficient technologies. Increasing the stringency of the emissions cap plays an important role in driving technological change, as is clearly evident in Figure 78, and by 2050 the emissions spread between the Deep GHG Reduction Scenario and its variants is quite large. In fact, annual GHG emissions in 2050 in the five scenario variants are lower than in the original Reference Case by 21%, 63%, 70%, 78%, and 85%, respectively. Particularly in the Deep GHG scenario variants, the reductions stem from energy system development paths that actually quite different from each other. Nevertheless, it is interesting to note that up until about 2020–2025, these landscapes are still quite similar, and the GHG emissions trajectories of each do not diverge until about this time. Such a result essentially says that whether California ultimately decides to follow a 50% or 80% GHG reduction path, or any path in between, technological investment decisions and fuel choices made over the coming decade (2010-2020) will, for the most part, need to be the same.

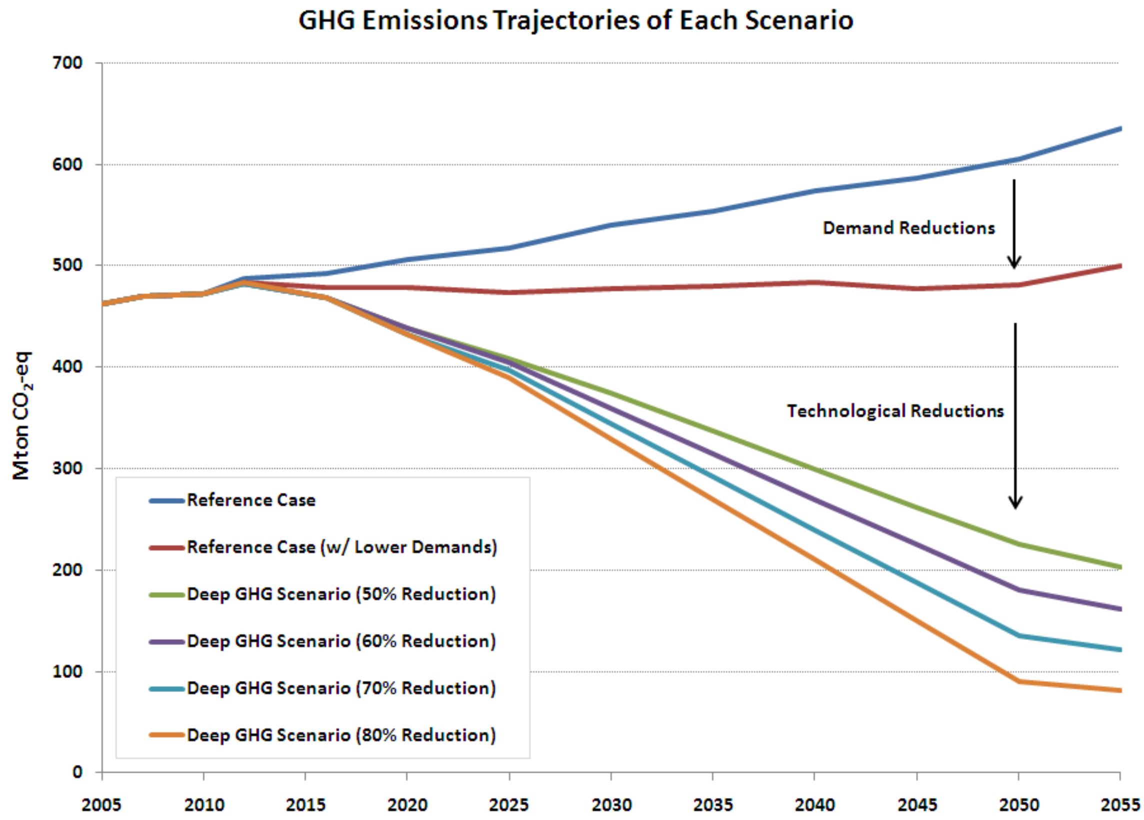


**Figure 78  GHG Trajectories of the Scenario Variants with Modified Emissions Caps**

The following series of tables shows a number of indicators comparing the Reference Case, Deep GHG Reduction Scenario, and their variants across several different dimensions. Particular attention is paid to the transportation sector, electricity generation, biofuels and biomass supply, and emissions. A fairly small number of indicators are shown (out of the hundreds or thousands possible), but the point here is to give the reader a quick sense of what these scenarios look like and how the stringency of the emissions cap impacts the development of the energy system in a different way. For instance, targeting deeper reductions in GHG emissions necessitates greater electrification of the light-duty vehicle fleet, namely PHEVs and Hydrogen FCVs (

Table 40). In the Deep GHG 50% scenario, the total share of light-duty VMT supplied by PHEVs, BEVs, and FCVs is just 11% in 2050, whereas it rises to 28% in the Deep GHG 80% scenario. Electrification of vehicles has the effect of raising the average fuel economy of the entire 2050 LDV fleet (both on-road and new cars and trucks) from 55 mpgge to 60 mpgge in these two scenarios, respectively. Simultaneously, because of the much greater use of low-carbon biofuels, electricity, and hydrogen, the average lifecycle carbon intensity of all fuels consumed in the California transportation sector in 2050 declines from 53.2 $gCO_2$-eq/$MJ_{HHV}$ in the Deep GHG 50% scenario to 31.1 $gCO_2$-eq/$MJ_{HHV}$ in the Deep GHG 80% scenario. Furthermore, while the light-duty vehicle fleet becomes increasingly electrified, in no scenarios do we see a penetration of battery-electric vehicles, which as described previously has everything to do with the relatively high lifecycle costs of supplying VMT using mid-sized BEVs with relatively large batteries, considering both the capital costs of vehicles and their requisite recharging infrastructure.

**Table 40 Comparison of Key Transportation Indicators for Scenario Variants with Modified Emissions Caps**

| Transportation Indicators | | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Share of LDV VMT Supplied by PHEVs | Reference Case | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (50% Reduction) | 0.0% | 1.4% | 12.5% | 12.4% | 10.9% |
| | Deep GHG Scenario (60% Reduction) | 0.0% | 1.4% | 12.5% | 12.4% | 10.9% |
| | Deep GHG Scenario (70% Reduction) | 0.0% | 1.4% | 12.5% | 12.4% | 10.8% |
| | Deep GHG Scenario (80% Reduction) | 0.0% | 1.4% | 12.9% | 11.1% | 22.3% |
| Share of LDV VMT Supplied by BEVs | Reference Case | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (50% Reduction) | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% |
| | Deep GHG Scenario (60% Reduction) | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% |
| | Deep GHG Scenario (70% Reduction) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (80% Reduction) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Share of LDV VMT Supplied by FCVs | Reference Case | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (50% Reduction) | 0.0% | 0.1% | 0.6% | 0.0% | 0.0% |
| | Deep GHG Scenario (60% Reduction) | 0.0% | 0.1% | 0.6% | 0.0% | 0.0% |
| | Deep GHG Scenario (70% Reduction) | 0.0% | 0.2% | 0.7% | 0.0% | 0.1% |
| | Deep GHG Scenario (80% Reduction) | 0.0% | 0.2% | 0.7% | 2.4% | 5.6% |
| Average LDV Fleet Fuel Economy (mpgge, test-cycle) | Reference Case | 25.8 | 30.7 | 34.2 | 35.1 | 35.9 |
| | Reference Case (w/ Lower Demands) | 25.8 | 30.8 | 35.0 | 36.1 | 37.0 |
| | Deep GHG Scenario (50% Reduction) | 25.8 | 32.3 | 48.3 | 53.8 | 54.6 |
| | Deep GHG Scenario (60% Reduction) | 25.8 | 32.3 | 48.3 | 53.8 | 54.6 |
| | Deep GHG Scenario (70% Reduction) | 25.8 | 32.3 | 48.3 | 53.8 | 54.6 |
| | Deep GHG Scenario (80% Reduction) | 25.8 | 32.3 | 48.3 | 53.8 | 59.6 |
| Average New Model Year LDV Fuel Economy (mpgge, test-cycle) | Reference Case | 25.8 | 34.1 | 34.2 | 35.6 | 36.3 |
| | Reference Case (w/ Lower Demands) | 25.8 | 34.3 | 35.5 | 36.7 | 36.9 |
| | Deep GHG Scenario (50% Reduction) | 25.8 | 41.3 | 53.9 | 54.2 | 54.7 |
| | Deep GHG Scenario (60% Reduction) | 25.8 | 41.3 | 53.9 | 54.2 | 54.7 |
| | Deep GHG Scenario (70% Reduction) | 25.8 | 41.3 | 53.9 | 54.2 | 54.7 |
| | Deep GHG Scenario (80% Reduction) | 25.8 | 41.3 | 53.9 | 54.2 | 65.6 |
| Average Carbon Intensity of All Transportation Fuels ($gCO2\text{-}eq/MJ_{HHV}$) | Reference Case | 83.0 | 80.8 | 78.8 | 75.6 | 75.1 |
| | Reference Case (w/ Lower Demands) | 83.0 | 80.0 | 77.7 | 74.2 | 73.3 |
| | Deep GHG Scenario (50% Reduction) | 83.0 | 79.4 | 71.5 | 60.3 | 53.2 |
| | Deep GHG Scenario (60% Reduction) | 83.0 | 79.4 | 69.6 | 54.3 | 45.6 |
| | Deep GHG Scenario (70% Reduction) | 83.0 | 79.4 | 67.8 | 49.8 | 38.1 |
| | Deep GHG Scenario (80% Reduction) | 83.0 | 79.4 | 65.9 | 46.7 | 31.1 |

Climate policies of greater stringency also have the effect decarbonizing the electric generation mix to increasingly lower levels (Table 41). The contribution from nuclear power is roughly the same in each of the Deep GHG scenarios; however, generation from renewable sources and from fossil and biomass plants equipped with CCS grows higher. These differences lead to average carbon intensities for electricity in 2050 that range from 35 $gCO_2$-eq/kWh in the Deep GHG 50% scenario to -11 $gCO_2$-eq/kWh in the Deep GHG 80% scenario (9.7 and -3.1 $gCO_2$-eq/$MJ_{HHV}$, respectively).

**Table 41 Comparison of Key Electricity Generation Indicators for Scenario Variants with Modified Emissions Caps**

| Electricity Generation Indicators | | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Share of Renewable & Hydro Electricity in Total Generation | Reference Case | 20.2% | 18.6% | 16.4% | 17.4% | 35.7% |
| | Reference Case (w/ Lower Demands) | 20.3% | 19.4% | 17.9% | 20.2% | 42.5% |
| | Deep GHG Scenario (50% Reduction) | 20.3% | 42.4% | 40.9% | 40.1% | 47.3% |
| | Deep GHG Scenario (60% Reduction) | 20.3% | 42.4% | 40.9% | 40.1% | 50.2% |
| | Deep GHG Scenario (70% Reduction) | 20.3% | 42.4% | 41.0% | 41.7% | 51.1% |
| | Deep GHG Scenario (80% Reduction) | 20.2% | 42.4% | 41.1% | 48.3% | 58.7% |
| Share of Nuclear Electricity in Total Generation | Reference Case | 12.4% | 11.2% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 12.4% | 11.7% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (50% Reduction) | 12.4% | 9.6% | 9.7% | 18.1% | 25.2% |
| | Deep GHG Scenario (60% Reduction) | 12.4% | 9.6% | 9.7% | 18.1% | 25.2% |
| | Deep GHG Scenario (70% Reduction) | 12.4% | 13.6% | 13.0% | 21.1% | 27.8% |
| | Deep GHG Scenario (80% Reduction) | 12.4% | 13.8% | 13.2% | 21.2% | 24.6% |
| Share of Fossil & Biomass w/ CCS Electricity in Total Generation | Reference Case | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (50% Reduction) | 0.0% | 0.0% | 2.2% | 8.2% | 14.1% |
| | Deep GHG Scenario (60% Reduction) | 0.0% | 0.0% | 2.7% | 8.9% | 15.0% |
| | Deep GHG Scenario (70% Reduction) | 0.0% | 0.0% | 3.0% | 9.2% | 14.9% |
| | Deep GHG Scenario (80% Reduction) | 0.0% | 0.0% | 6.3% | 12.1% | 15.7% |
| Average Carbon Intensity of Electricity (gCO2-eq/kWh) | Reference Case | 317 | 337 | 308 | 277 | 210 |
| | Reference Case (w/ Lower Demands) | 317 | 334 | 306 | 272 | 186 |
| | Deep GHG Scenario (50% Reduction) | 317 | 239 | 169 | 110 | 35 |
| | Deep GHG Scenario (60% Reduction) | 317 | 239 | 165 | 104 | 19 |
| | Deep GHG Scenario (70% Reduction) | 317 | 223 | 159 | 85 | 5 |
| | Deep GHG Scenario (80% Reduction) | 317 | 222 | 146 | 53 | -11 |

Biomass supply and biofuels consumption are strong in each of the Deep GHG scenario variants (Table 42). In fact, because of the attractive of achieving emissions reductions through utilization of negative emissions bio-CCS technologies, the scenarios with 50%, 60%, and 70% reduction targets have biomass/biofuels demands that are about the same in 2050 as in the Deep GHG 80% scenario – biomass consumption of 1,669 to 1,737 PJ, or 104 to 108 million bone dry tons; biofuels consumption of 972 to 1,019 PJ, or 7.41 to 7.77 billion gge. Actually, these levels are approximately the same as in the Reference

Case, though the types of biofuels being produced are markedly different (more cellulosic ethanol and less bio-based gasoline, diesel, and jet fuel in the Reference Case).

**Table 42 Comparison of Key Biofuels and Biomass Indicators for Scenario Variants with Modified Emissions Caps**

| Biofuels & Biomass Indicators | | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biofuels Consumption (PJ) | Reference Case | 164 | 419 | 632 | 946 | 1044 |
| | Reference Case (w/ Lower Demands) | 164 | 447 | 647 | 937 | 1039 |
| | Deep GHG Scenario (50% Reduction) | 164 | 441 | 513 | 795 | 972 |
| | Deep GHG Scenario (60% Reduction) | 164 | 441 | 614 | 877 | 1019 |
| | Deep GHG Scenario (70% Reduction) | 164 | 439 | 690 | 937 | 976 |
| | Deep GHG Scenario (80% Reduction) | 164 | 439 | 728 | 951 | 975 |
| Biomass Supply (PJ) | Reference Case | 148 | 448 | 785 | 1210 | 1598 |
| | Reference Case (w/ Lower Demands) | 148 | 471 | 751 | 1159 | 1555 |
| | Deep GHG Scenario (50% Reduction) | 148 | 744 | 914 | 1407 | 1669 |
| | Deep GHG Scenario (60% Reduction) | 148 | 744 | 974 | 1534 | 1732 |
| | Deep GHG Scenario (70% Reduction) | 148 | 742 | 1026 | 1580 | 1732 |
| | Deep GHG Scenario (80% Reduction) | 148 | 729 | 1067 | 1581 | 1737 |

Table 43 highlights some key GHG emissions indicators of the scenarios, for example, total energy sector GHG emissions in California relative to projected sizes of the state's population and economy. Also shown are total cumulative GHG emissions over the entire model time horizon and the annual quantity of emissions that are captured and stored underground via CCS. In all instances, the trends appear sensible: GHG emissions per capita and per GSP decline to increasingly lower levels as the climate policy becomes more stringent, and utilization of CCS grows as the GHG reduction targets become stricter.

**Table 43 Comparison of Key GHG Emissions Indicators for Scenario Variants with Modified Emissions Caps**

| GHG Emissions Indicators | | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| GHG Emissions Relative to Gross State Product ($tCO_2e$ per M$ GSP) | Reference Case | 256 | 211 | 174 | 143 | 117 |
| | Reference Case (w/ Lower Demands) | 256 | 200 | 154 | 121 | 93 |
| | Deep GHG Scenario (50% Reduction) | 256 | 183 | 121 | 75 | 43 |
| | Deep GHG Scenario (60% Reduction) | 256 | 183 | 116 | 67 | 35 |
| | Deep GHG Scenario (70% Reduction) | 256 | 181 | 111 | 60 | 26 |
| | Deep GHG Scenario (80% Reduction) | 256 | 181 | 106 | 52 | 17 |
| GHG Emissions per Capita ($tCO_2e$ per person) | Reference Case | 12.1 | 11.5 | 11.0 | 10.6 | 10.2 |
| | Reference Case (w/ Lower Demands) | 12.1 | 10.9 | 9.7 | 8.9 | 8.1 |
| | Deep GHG Scenario (50% Reduction) | 12.1 | 9.9 | 7.6 | 5.5 | 3.8 |
| | Deep GHG Scenario (60% Reduction) | 12.1 | 9.9 | 7.3 | 5.0 | 3.0 |
| | Deep GHG Scenario (70% Reduction) | 12.1 | 9.8 | 7.0 | 4.4 | 2.3 |
| | Deep GHG Scenario (80% Reduction) | 12.1 | 9.8 | 6.7 | 3.9 | 1.5 |
| GHG Emissions Captured and Stored via CCS (Mton $CO_2e$) | Reference Case | 0 | 0 | 0 | 0 | 0 |
| | Reference Case (w/ Lower Demands) | 0 | 0 | 0 | 0 | 0 |
| | Deep GHG Scenario (50% Reduction) | 0 | 0 | 7 | 59 | 115 |
| | Deep GHG Scenario (60% Reduction) | 0 | 0 | 11 | 71 | 135 |
| | Deep GHG Scenario (70% Reduction) | 0 | 0 | 18 | 79 | 152 |
| | Deep GHG Scenario (80% Reduction) | 0 | 0 | 26 | 91 | 166 |
| Cumulative GHG Emissions, 2005-2055 (Mton $CO_2e$) | Reference Case | | | 27,552 | | |
| | Reference Case (w/ Lower Demands) | | | 24,433 | | |
| | Deep GHG Scenario (50% Reduction) | | | 18,498 | | |
| | Deep GHG Scenario (60% Reduction) | | | 17,609 | | |
| | Deep GHG Scenario (70% Reduction) | | | 16,670 | | |
| | Deep GHG Scenario (80% Reduction) | | | 15,762 | | |

Costs are another important metric by which to compare the Deep GHG Reduction Scenario and its variants with the Reference Case. Figure 79 shows cumulative total discounted energy system costs for each of these scenarios. Energy system costs include all investment, fixed and variable O&M, and resource/fuel costs accounted for in the CA-TIMES model. (Note that investments and O&M costs in the industrial, commercial, residential, and agricultural end-use sectors are not captured, but at least fuel costs are accounted for.) The first observation one makes is that costs in the Reference Case (w/ Lower Demands) are lower than in the original Reference Case by a fair amount. This result illustrates the importance of controlling the future growth of end-use demands, which can lead to significantly reduced capital investment requirements and substantial O&M and fuel savings. (Of course, the steps taken to reduce demand are themselves likely to incur costs that are non-trivial, and so long as they are made outside of the energy system, they are not captured by the CA-TIMES model.) Second, total costs appear to increase with the stringency of the emission reduction target. Compared to the Reference Case (w/ Lower Demands), for example, costs are between 7.3% and 9.7% higher in the Deep GHG scenarios. Interestingly, the jump from a 70% to 80% target necessitates a greater incremental cost increase than for the other scenario variants (i.e., from 50% to 60%, and 60% to 70%). Moreover, while investment costs continue to rise under increasingly stringent climate policy, variable costs (namely fuel costs) remain roughly constant, and compared to the Reference Case (w/ Lower Demands), variable costs are actually smaller. For instance, while cumulative investment costs are estimated to be \$1.34 trillion greater in the Deep GHG 80% scenario than in the Reference Case (w/ Lower Demands), variable and O&M costs are actually \$0.41 trillion lower. These are important results because they show that the although the per-unit cost of fuels may be higher in the Deep GHG scenarios, total aggregate fuel costs across the entire energy system are lower, as a result of greatly increased technological efficiencies in all sectors.

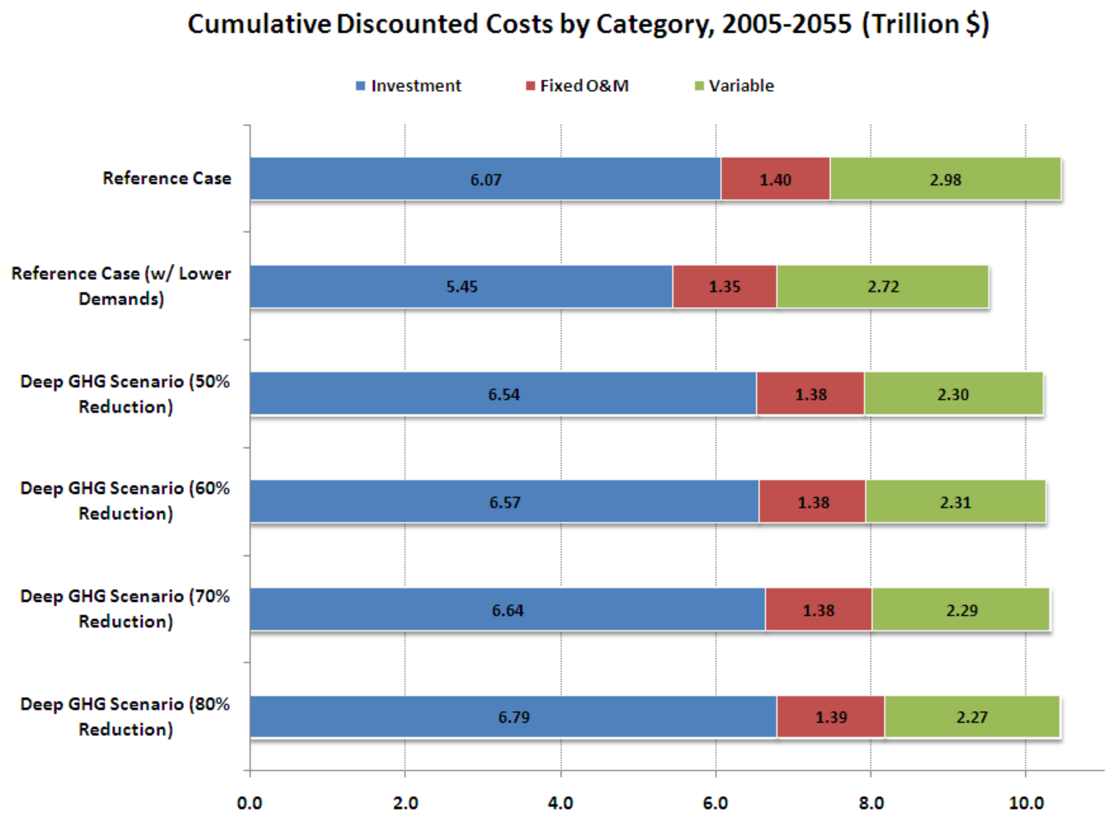


**Figure 79 Comparison of Cumulative Total Discounted Energy System Costs for Scenario Variants with Modified Emissions Caps**

While the costs of the scenarios may seem high at first glance (in the trillions of dollars), they actually only make up a fraction of California's projected cumulative discounted GSP over the same time period.

Table 44 shows that the climate policies of the Deep GHG scenarios (50% to 80% reductions) add about 1.1 to 1.5 percentage points to total energy system costs (as a share of cumulative discounted GSP). In fact, in none of the Deep GHG scenarios are the costs incurred any greater than in the original Reference Case, again highlighting the important effect of demand reduction.

**Table 44  Comparison of Key Cost Indicators for Scenario Variants with Modified Emissions Caps**

| Cost Indicators | | | *Notes* |
|---|---|---|---|
| **Cumulative Discounted System Costs, 2005-2055** | Reference Case | 9.8% | *Costs are relative to Reference Case (w/ Lower Demands)* |
| | Reference Case (w/ Lower Demands) | -- | |
| | Deep GHG Scenario (50% Reduction) | 7.3% | |
| | Deep GHG Scenario (60% Reduction) | 7.7% | |
| | Deep GHG Scenario (70% Reduction) | 8.3% | |
| | Deep GHG Scenario (80% Reduction) | 9.7% | |
| **Cumulative Discounted System Costs as a Share of Cumulative Discounted GSP, 2005-2055** | Reference Case | 1.5% | *Costs are relative to Reference Case (w/ Lower Demands)* |
| | Reference Case (w/ Lower Demands) | -- | |
| | Deep GHG Scenario (50% Reduction) | 1.1% | |
| | Deep GHG Scenario (60% Reduction) | 1.2% | |
| | Deep GHG Scenario (70% Reduction) | 1.3% | |
| | Deep GHG Scenario (80% Reduction) | 1.5% | |
| **Average Cost of GHG Abatement ($ per $tCO_2e$)** | Reference Case | -- | *Costs and GHGs are relative to Reference Case (w/ Lower Demands)* |
| | Reference Case (w/ Lower Demands) | -- | |
| | Deep GHG Scenario (50% Reduction) | 118 | |
| | Deep GHG Scenario (60% Reduction) | 107 | |
| | Deep GHG Scenario (70% Reduction) | 102 | |
| | Deep GHG Scenario (80% Reduction) | 107 | |

It should be noted that in estimating costs relative to GSP, the results presented here do not account for investment and O&M costs in the industrial, commercial, residential, commercial, and agricultural end-use sectors.  And while not the focus of the current study, this undoubtedly leaves a gaping hole in the analysis.  That being said, it is not entirely clear that the results shown here on a relative change basis would differ markedly if these other sectors were added to the model in bottom-up technological detail.  After all, absolute costs would rise in all scenarios, including the Reference Case, and thus relative changes could theoretically remain the same.  The exact change would, of course, depend on the relative costs of deploying advanced technologies to reduce GHG emissions in the ICRA sectors.  If the marginal costs of doing so were less than for the sectors explicitly modeled in the current version of CA-TIMES (transport, electricity, supply), one might even expect the relative increases for total energy system costs to be lower than those discussed here.

Another potentially useful metric for comparing the relative costs of the Deep GHG scenario variants is the average cost of GHG abatement over the entire model time horizon.  For a given scenario, this is calculated as the difference in cumulative total discounted energy system costs relative to the Reference Case (w/ Lower Demands) divided by the cumulative emissions of the same scenario relative to the Reference Case (w/ Lower Demands).

Table 44 summarizes these values for each of the Deep GHG scenarios. Average costs are in the range of \$102 to \$118 per tonne of $CO_2$-equivalent, which means that marginal costs of emissions abatement range from well below this average (i.e., near zero) all the way up to several hundred dollars per tonne. Of particular note is the fact that the average cost of abatement is actually lower for the more stringent climate scenarios. Generally, one would expect average abatement costs to exhibit an upward trend with increasingly stringent climate policy, as shown previously for total system costs. Presumably, this has to do with the specific timing of energy investments and the fact that on a net present value basis utilization of a non-zero discount rate makes costs incurred in later time periods less significant in the calculation of total energy system costs.

The transportation sector is responsible for an overwhelming share of the total capital investment costs shown in Figure 79, with electric sector investments coming a distant second (see Figure 80). In particular, capital costs of light-duty vehicles account for about 50-55% of all transport sector investments (which interestingly is roughly the same level as the subsector's share of energy use and GHG emissions in the overall transport total). One of the reasons why transport sector investments – especially for LDVs – are so disproportionately high is that cars, trucks, buses, ships, airplanes, and trains are relatively expensive energy production devices, when viewed on a \$/MJ basis, compared to power plants, refineries, and other fuel conversion facilities.[52] In addition to the

[52] Firstly, the efficiency of converting a MJ of fuel to a MJ of useful work is substantially lower for transportation vehicles, due to the range of parasitic, dissipative, aerodynamic and hydrodynamic drag, and other losses that come into play. Secondly, the capacity factors of transportation vehicles, particularly private motor vehicles, are extremely low compared to energy supply facilities, some of which operate almost continuously. For example, a typical light-duty car or truck is used for perhaps a handful of trips a day, and for just an hour in total time. The remainder of the day, the vehicle, and all the capital investment that went into producing it, sits idle. Heavy- and medium-duty trucks, ships, airplanes, and trains are much

transport and electric sectors, imposition of increasingly stringent climate policies leads to larger investments in the hydrogen and syn-fuels industries (Figure 80). At the same time, investments in the fossil fuels and biofuels industries decline. (Note that by this definition, production of bio-based gasoline, diesel, and jet fuel at FT poly-generation plants is accounted for in the syn-fuels industry.) The diminishing importance of the fossil fuels industry is an intuitive result, but that of the biofuels industry requires a bit of explanation. As the model attempts to meet the lower emissions targets of the Deep GHG scenarios, it relies less heavily on certain biofuels production technologies – namely cellulosic ethanol (via biochemical and thermochemical pathways) and biodiesel (via hydrotreatment) – and instead it shifts limited biomass resources to FT poly-generation plants equipped with CCS.

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better in this respect, since they are treated more like business investments; however, they are still relatively expensive means by which to produce useful work.

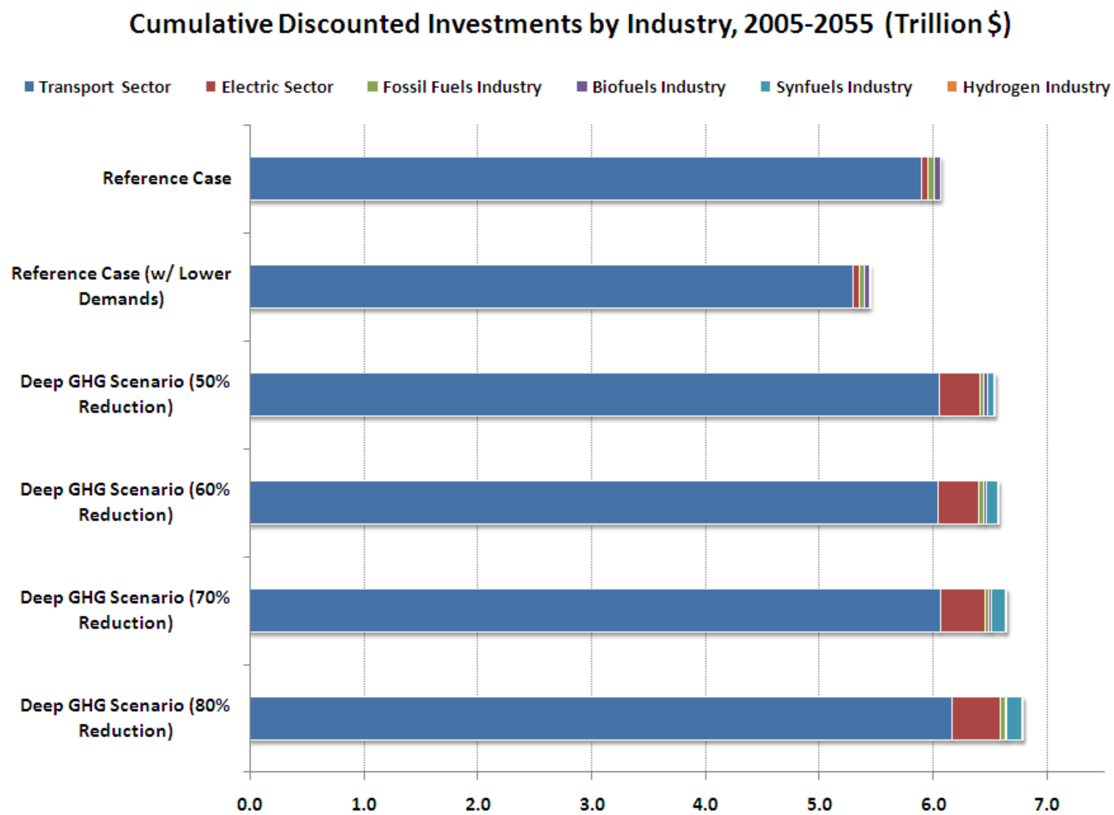


**Figure 80 Comparison of Cumulative Discounted Energy Investments for Scenario Variants with Modified Emissions Caps**

On a final note, even though the fossil industry is seen to shrink in the low-carbon futures described here, it may very well be the case that the same players continue to be involved, as today's large fuel producers and energy companies are likely to be the only ones capable of making the necessary, but huge, capital investments in syn-fuels and hydrogen production/distribution capacity over the coming decades. In other words, the industry may look different, but the names may be the same.

*Scenario Variants #2: Modification of Key Resource and Technology Potentials*

To be sure, the stringency of future climate policy is by no means the only uncertainty going forward. The potential of certain key resources and technologies to mitigate greenhouse gas emissions on a large scale is also not yet fully understood at the present time. For instance, many questions still remain regarding the availability of sustainable biomass in large quantities; the risks associated with and social acceptance of nuclear power and carbon capture and storage; the ability of batteries to meet the stringent demands of transport vehicles; and the well-known "chicken and egg" dilemma for initiating hydrogen infrastructure. In an effort to partially address these questions, I develop several additional variants of the original Deep GHG Reduction Scenario in this section. As with the first set of scenario variants dealing with the stringency of the emissions cap, all assumptions are the same in these scenarios as they are in the core Deep GHG Reduction Scenario. Importantly, fuel demands in the ICRA sectors remain the same as before.

- ***Deep GHG Reduction Scenario (Low Biomass)***

  Assumes the potential supply of sustainable biomass in California and the Western U.S. is 50% lower than in the original Deep GHG Reduction Scenario. The supply curves for each type of biomass feedstock retain their same shapes (i.e., same price levels), but the quantities available at each step and for each type of biomass are reduced.

- ***Deep GHG Reduction Scenario (High Biomass)***

  Assumes the potential supply of sustainable biomass in California and the Western U.S. is 50% greater than in the original Deep GHG Reduction Scenario. The supply curves for each type of biomass feedstock retain their same shapes (i.e., same price levels), but the quantities available at each step and for each type of biomass are increased.

- ***<u>Deep GHG Reduction Scenario (No Nuclear or CCS)</u>***

  Assumes that due to basic NIMBY ("Not In My Backyard") issues and societal concerns over, for example, nuclear waste and security and $CO_2$ leakage and groundwater contamination, neither new nuclear power nor CCS ever become viable technological options within the California energy system. No new nuclear plants are allowed to be built, and no carbon capture and storage ever takes place. The GHG mitigation potential of these technologies is, therefore, zero in all future years.

- ***<u>Deep GHG Reduction Scenario (Limited EV-FCV Success)</u>***

  Assumes that on the one hand battery technology never matures to the point where consumer demands for vehicle size, power, and range are met at reasonable cost (or alternately, that consumers never become willing to sacrifice these attributes by adopting smaller, less powerful vehicles), and that at the same time the chicken and egg problem for centralized hydrogen production and distribution proves to be impossible to overcome at large scale. Thus, BEVs and PHEVs are substantially more limited in the share of LDV, MDT, and Bus VMT they are able to supply. (For example, in the light-duty subsector, the original Deep GHG Reduction Scenario assumed that no more than 50% of VMT could be supplied jointly by BEVs and PHEVs due to real limits on the number of people who would be able to recharge at home or work (O'Connor, 2007b). However, in this scenario variant the share is reduced to just 25%.) In the case of FCVs, only distributed production of hydrogen is possible at refueling stations and fleet vehicle depots, and the availability of this infrastructure is fairly limited in scope (maximum 200 PJ, or 1.41 million metric tonnes, of hydrogen production in any year).

Figure 81 compares the GHG emissions trajectories of the Reference Case, Reference Case (w/ Lower Demands), and these new variants of the Deep GHG Reduction Scenario. The first thing one notices is that not all scenarios are able to meet the 80% reduction target. In fact, only the High Biomass and Limited EV-FCV Success scenarios are able to make such deep reductions, whereas imposing such a stringent target in the other scenarios leads to model infeasibilities. This is not to say that it is absolutely impossible to make an 80% cut in GHGs without a large supply of biomass and without widespread success of nuclear or CCS. Rather, the scenarios show that, based on the current assumptions input to the model, it becomes extremely difficult to meet such a target if the potential of any of these key resources and technologies is significantly limited. In other words, meeting California’s long-term goal of an 80% reduction in GHG emissions essentially requires that every major technological and fuel option remains on the table (i.e., a multi-strategy, portfolio approach is needed). If some of these options are unavailable, then demand reduction through even more aggressive energy and conservation efforts would have to play a much greater role in helping to bring emissions down to lower levels. Nevertheless, while deep cuts in GHGs depend strongly on the availability of technologies, it is quite interesting to note that large reductions still appear to be possible by 2050 in these other scenario variants: Low Biomass (70% reduction) and No Nuclear or CCS (65%).

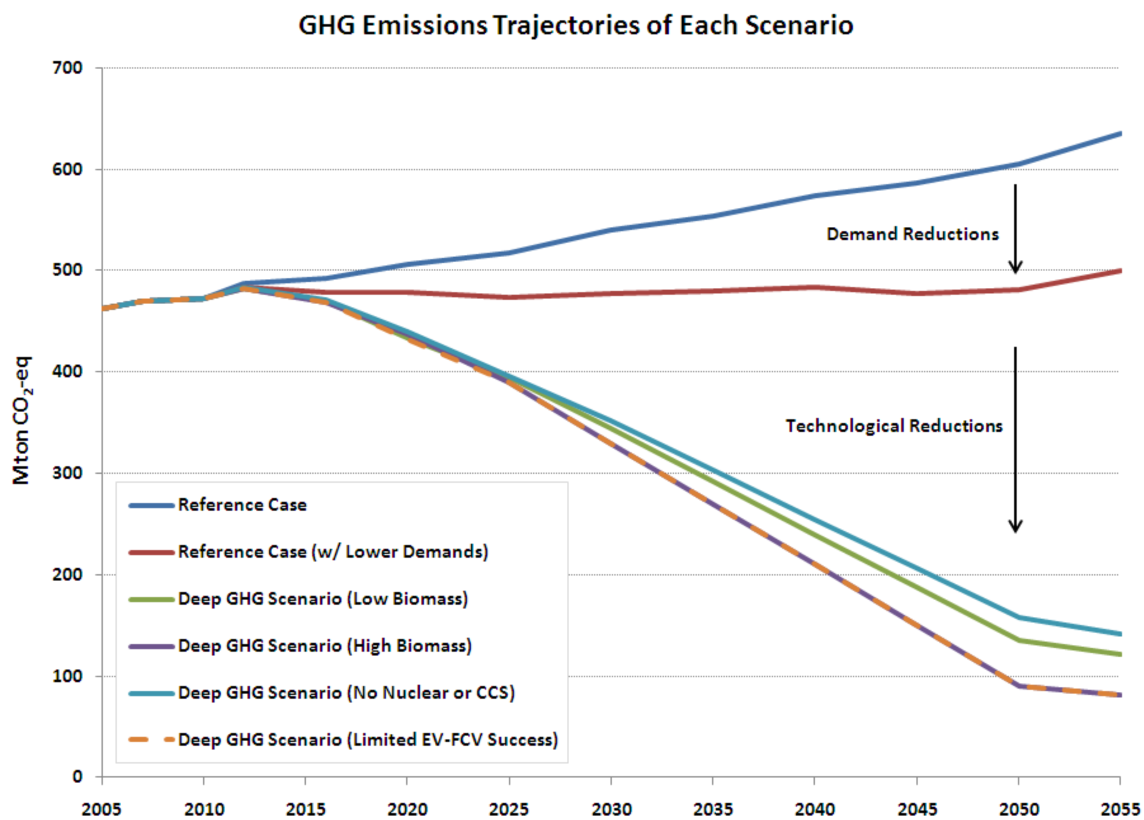


**Figure 81 GHG Trajectories of the Scenario Variants with Modified Resource and Technology Potentials**

Because these scenario variants do not meet the 80% reduction target in all cases, it is a little difficult to compare them with the original Deep GHG Reduction Scenario. Perhaps a more useful exercise is to compare them with the first set of scenario variants, which, as discussed in the previous section, look at emissions caps of varying stringencies. For example, the Low Biomass scenario reduces GHGs 70% below 1990 levels by 2050, but the way these reductions are made is a bit different than in the Deep GHG 70% scenario variant from above. Notably, because supplies of biomass, and thus biofuels, are so limited in the Low Biomass scenario, the model relies more heavily on electricity and hydrogen in the transport sector, especially for light-duty vehicles (Table 45). Whereas the share of LDV VMT supplied by PHEVs, BEVs, and FCVs was about 11% in the

Deep GHG 70% scenario, it is a much greater 70% in the Deep GHG Low Biomass scenario. For this reason, average fleet fuel economy is higher in 2050 in the latter case: 75.1 vs. 54.6 mpgge. In contrast, when assuming much more optimistic levels of biomass availability, as in the High Biomass scenario, there is less of a need for hydrogen, and the penetration of FCVs in the LDV subsector is a bit lower: 11% in the Deep GHG High Biomass scenario compared to 28% in the original Deep GHG Reduction Scenario (both of these scenarios meet the 80% reduction target in 2050).

**Table 45 Comparison of Key Transportation Indicators for Scenario Variants with Modified Resource and Technology Potentials**

| Transportation Indicators | | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Share of LDV VMT Supplied by PHEVs | Reference Case | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (Low Biomass) | 0.0% | 1.4% | 11.8% | 19.0% | 42.1% |
| | Deep GHG Scenario (High Biomass) | 0.0% | 1.4% | 12.5% | 12.4% | 10.9% |
| | Deep GHG Scenario (No Nuclear or CCS) | 0.0% | 1.4% | 16.1% | 22.1% | 50.0% |
| | Deep GHG Scenario (Limited EV-FCV Success) | 0.0% | 1.4% | 12.8% | 11.7% | 24.3% |
| Share of LDV VMT Supplied by BEVs | Reference Case | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (Low Biomass) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (High Biomass) | 0.0% | 0.0% | 0.1% | 0.0% | 0.0% |
| | Deep GHG Scenario (No Nuclear or CCS) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (Limited EV-FCV Success) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| Share of LDV VMT Supplied by FCVs | Reference Case | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (Low Biomass) | 0.0% | 0.2% | 2.5% | 8.7% | 18.7% |
| | Deep GHG Scenario (High Biomass) | 0.0% | 0.1% | 0.6% | 0.0% | 0.0% |
| | Deep GHG Scenario (No Nuclear or CCS) | 0.0% | 0.3% | 3.2% | 11.3% | 26.4% |
| | Deep GHG Scenario (Limited EV-FCV Success) | 0.0% | 0.2% | 0.7% | 1.8% | 4.2% |
| Average LDV Fleet Fuel Economy (mpgge, test-cycle) | Reference Case | 25.8 | 30.7 | 34.2 | 35.1 | 35.9 |
| | Reference Case (w/ Lower Demands) | 25.8 | 30.8 | 35.0 | 36.1 | 37.0 |
| | Deep GHG Scenario (Low Biomass) | 25.8 | 32.3 | 48.3 | 55.2 | 75.1 |
| | Deep GHG Scenario (High Biomass) | 25.8 | 32.3 | 48.3 | 53.8 | 54.6 |
| | Deep GHG Scenario (No Nuclear or CCS) | 25.8 | 32.3 | 48.3 | 57.9 | 83.7 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 25.8 | 32.3 | 48.3 | 53.8 | 60.7 |
| Average New Model Year LDV Fuel Economy (mpgge, test-cycle) | Reference Case | 25.8 | 34.1 | 34.2 | 35.6 | 36.3 |
| | Reference Case (w/ Lower Demands) | 25.8 | 34.3 | 35.5 | 36.7 | 36.9 |
| | Deep GHG Scenario (Low Biomass) | 25.8 | 41.3 | 53.9 | 58.2 | 107.3 |
| | Deep GHG Scenario (High Biomass) | 25.8 | 41.3 | 53.9 | 54.2 | 54.7 |
| | Deep GHG Scenario (No Nuclear or CCS) | 25.8 | 41.3 | 53.9 | 67.0 | 104.3 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 25.8 | 41.3 | 53.9 | 54.2 | 68.3 |
| Average Carbon Intensity of All Transportation Fuels ($gCO2-eq/MJ_{HHV}$) | Reference Case | 83.0 | 80.8 | 78.8 | 75.6 | 75.1 |
| | Reference Case (w/ Lower Demands) | 83.0 | 80.0 | 77.7 | 74.2 | 73.3 |
| | Deep GHG Scenario (Low Biomass) | 83.0 | 80.0 | 72.4 | 58.0 | 43.8 |
| | Deep GHG Scenario (High Biomass) | 83.0 | 79.4 | 63.1 | 42.9 | 28.0 |
| | Deep GHG Scenario (No Nuclear or CCS) | 83.0 | 79.6 | 68.7 | 57.8 | 43.4 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 83.0 | 79.4 | 65.8 | 47.5 | 31.5 |

The results of this study illustrate that bio-CCS negative emissions technologies can be a cost-effective means by which to significantly reduce California energy system emissions. When these technologies are available, the model fully maximizes their utilization (subject to constraints on biomass supply) and at the same time chooses not to decarbonize the transport sector to a significant degree. However, when CCS is eliminated from the potential technology mix, the situation changes drastically. For instance, Table 45 shows that in the Deep GHG No Nuclear or CCS scenario, the contribution of PHEVs, BEVs, and FCVs to total LDV VMT rises to 76%, thus raising the fleet-average fuel economy of all on-road light-duty cars and trucks to 83.7 mpgge by 2050. In sum, when bio-CCS is on the table, the more advanced vehicle technologies (especially BEVs and FCVs) may not actually be needed to reach the deep GHG reduction targets; instead, HEVs and PHEVs fueled by a mixture of conventional and bio-based gasoline and E-85 ethanol may be able to suffice.

The impact of removing both nuclear power and CCS from the technology portfolio is also evident in the electric sector. For the most part, the electric generation mix is consistent between the scenario variants shown here and the previous set with modified emission caps. However, in the No Nuclear or CCS scenario the model is forced to supply electricity using a far greater share of renewable resources: 86% in the No Nuclear or CCS scenario (Table 46) compared to between 47% and 59% in the scenario variants with modified emission caps. Although not shown, the bulk of the renewable generation in the No Nuclear or CCS scenario is from solar and wind, though geothermal and hydro make important contributions as well. Due to the inherent mismatch between nighttime wind generation and daytime electricity loads (assuming no significant storage), the model estimates the upper limit on wind power, as a share of total generation, to be about 40%, a level that is somewhat higher than the 20-30% limits estimated by recent wind integration and transmission studies, albeit for the 2030 time horizon (NREL, 2010a, b). A reason for this discrepancy is the inability of CA-TIMES to analyze timing and intermittency issues on the level of seconds to minutes, but rather on the level of hours. In the real world, it could very well be the case that such high levels of renewable penetration are simply unrealistic from an operational standpoint, barring significant investments in storage capacity. Hence, by extension, it may be unrealistic to expect GHG reductions on the order of 50-80% if low-carbon options such as nuclear and CCS are altogether absent from the available technology portfolio. Future research with the CA-TIMES model will attempt to shed some more light on these issues.

**Table 46 Comparison of Key Electricity Generation Indicators for Scenario Variants with Modified Resource and Technology Potentials**

| Electricity Generation Indicators | | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Share of Renewable & Hydro Electricity in Total Generation | Reference Case | 20.2% | 18.6% | 16.4% | 17.4% | 35.7% |
| | Reference Case (w/ Lower Demands) | 20.3% | 19.4% | 17.9% | 20.2% | 42.5% |
| | Deep GHG Scenario (Low Biomass) | 20.3% | 42.4% | 45.6% | 55.8% | 65.4% |
| | Deep GHG Scenario (High Biomass) | 20.3% | 42.4% | 41.0% | 43.7% | 53.8% |
| | Deep GHG Scenario (No Nuclear or CCS) | 20.3% | 42.4% | 60.4% | 78.3% | 86.2% |
| | Deep GHG Scenario (Limited EV-FCV Success) | 20.3% | 42.4% | 41.2% | 49.6% | 60.9% |
| Share of Nuclear Electricity in Total Generation | Reference Case | 12.4% | 11.2% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 12.4% | 11.7% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (Low Biomass) | 12.4% | 13.8% | 13.2% | 20.8% | 20.7% |
| | Deep GHG Scenario (High Biomass) | 12.4% | 11.1% | 10.9% | 19.3% | 26.3% |
| | Deep GHG Scenario (No Nuclear or CCS) | 12.4% | 9.6% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (Limited EV-FCV Success) | 12.4% | 13.8% | 13.2% | 21.3% | 23.2% |
| Share of Fossil & Biomass w/ CCS Electricity in Total Generation | Reference Case | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Reference Case (w/ Lower Demands) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (Low Biomass) | 0.0% | 0.0% | 6.9% | 12.1% | 13.8% |
| | Deep GHG Scenario (High Biomass) | 0.0% | 0.0% | 3.2% | 9.4% | 14.3% |
| | Deep GHG Scenario (No Nuclear or CCS) | 0.0% | 0.0% | 0.0% | 0.0% | 0.0% |
| | Deep GHG Scenario (Limited EV-FCV Success) | 0.0% | 0.0% | 6.4% | 12.3% | 15.4% |
| Average Carbon Intensity of Electricity (gCO2-eq/kWh) | Reference Case | 317 | 337 | 308 | 277 | 210 |
| | Reference Case (w/ Lower Demands) | 317 | 334 | 306 | 272 | 186 |
| | Deep GHG Scenario (Low Biomass) | 317 | 223 | 124 | 34 | -6 |
| | Deep GHG Scenario (High Biomass) | 317 | 233 | 163 | 81 | 0 |
| | Deep GHG Scenario (No Nuclear or CCS) | 317 | 238 | 146 | 60 | 27 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 317 | 222 | 145 | 47 | -13 |

The Deep GHG Low Biomass scenario sees the use of only 489 PJ (3.7 billion gge) of biofuels in 2050 (Table 47), half that of the original Deep GHG Reduction Scenario. Most of this biofuel is in the form of bio-based residual fuel oil, diesel, jet fuel, and gasoline, with only a fraction coming from cellulosic ethanol. As has been previously discussed, when supplies of biomass/biofuels are limited, the results of this analysis indicate that biofuels are most optimally used in the non-LDV subsectors, due to inherent technological limitations on fuel switching to hydrogen and electricity in these other segments.  Results of the Deep GHG High Biomass scenario appear to lead to the same conclusion, except in this case the supply of biofuels is large enough (1,669 PJ in 2050, or 12.7 billion gge) that a GHG reduction target of 80% is able to be reached.  (In the Low Biomass scenario, only a 70% reduction is possible.)  Another interesting, even counter-intuitive, finding from the High Biomass scenario is that when the availability of biomass is extremely large, the model actually chooses to utilize less carbon capture and storage than in the original Deep GHG Reduction Scenario, where mid-range estimates for biomass supply are used (Table 48).  One might expect to see greater utilization of CCS when biomass supplies are large, because of the potential for negative emissions using bio-CCS technologies.  However, it seems that the high cost of CCS as a mitigation option is an impediment to its use, especially when the potential for “conventional” zero-emissions biomass conversion technologies is larger (e.g., bio-refineries and FT poly-generation plants *without* CCS).

**Table 47  Comparison of Key Biofuels and Biomass Indicators for Scenario Variants with Modified Resource and Technology Potentials**

| Biofuels & Biomass Indicators | | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| Biofuels Consumption (PJ) | Reference Case | 164 | 419 | 632 | 946 | 1044 |
| | Reference Case (w/ Lower Demands) | 164 | 447 | 647 | 937 | 1039 |
| | Deep GHG Scenario (Low Biomass) | 164 | 450 | 445 | 466 | 489 |
| | Deep GHG Scenario (High Biomass) | 164 | 440 | 843 | 1257 | 1669 |
| | Deep GHG Scenario (No Nuclear or CCS) | 164 | 430 | 652 | 920 | 973 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 164 | 438 | 720 | 951 | 975 |
| Biomass Supply (PJ) | Reference Case | 148 | 448 | 785 | 1210 | 1598 |
| | Reference Case (w/ Lower Demands) | 148 | 471 | 751 | 1159 | 1555 |
| | Deep GHG Scenario (Low Biomass) | 148 | 583 | 726 | 846 | 924 |
| | Deep GHG Scenario (High Biomass) | 148 | 755 | 1252 | 2187 | 2757 |
| | Deep GHG Scenario (No Nuclear or CCS) | 148 | 448 | 947 | 1536 | 1737 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 148 | 733 | 1069 | 1580 | 1737 |

**Table 48 Comparison of Key GHG Emissions Indicators for Scenario Variants with Modified Resource and Technology Potentials**

| GHG Emissions Indicators | | 2010 | 2020 | 2030 | 2040 | 2050 |
|---|---|---|---|---|---|---|
| GHG Emissions Relative to Gross State Product ($tCO_2e$ per M$ GSP) | Reference Case | 256 | 211 | 174 | 143 | 117 |
| | Reference Case (w/ Lower Demands) | 256 | 200 | 154 | 121 | 93 |
| | Deep GHG Scenario (Low Biomass) | 256 | 181 | 111 | 60 | 26 |
| | Deep GHG Scenario (High Biomass) | 256 | 183 | 106 | 52 | 17 |
| | Deep GHG Scenario (No Nuclear or CCS) | 256 | 184 | 114 | 64 | 30 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 256 | 181 | 106 | 52 | 17 |
| GHG Emissions per Capita ($tCO_2e$ per person) | Reference Case | 12.1 | 11.5 | 11.0 | 10.6 | 10.2 |
| | Reference Case (w/ Lower Demands) | 12.1 | 10.9 | 9.7 | 8.9 | 8.1 |
| | Deep GHG Scenario (Low Biomass) | 12.1 | 9.8 | 7.0 | 4.4 | 2.3 |
| | Deep GHG Scenario (High Biomass) | 12.1 | 9.9 | 6.7 | 3.9 | 1.5 |
| | Deep GHG Scenario (No Nuclear or CCS) | 12.1 | 10.0 | 7.2 | 4.7 | 2.6 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 12.1 | 9.8 | 6.7 | 3.9 | 1.5 |
| GHG Emissions Captured and Stored via CCS (Mton $CO_2e$) | Reference Case | 0 | 0 | 0 | 0 | 0 |
| | Reference Case (w/ Lower Demands) | 0 | 0 | 0 | 0 | 0 |
| | Deep GHG Scenario (Low Biomass) | 0 | 0 | 21 | 82 | 139 |
| | Deep GHG Scenario (High Biomass) | 0 | 0 | 22 | 83 | 145 |
| | Deep GHG Scenario (No Nuclear or CCS) | 0 | 0 | 0 | 0 | 0 |
| | Deep GHG Scenario (Limited EV-FCV Success) | 0 | 0 | 26 | 86 | 153 |
| Cumulative GHG Emissions, 2005-2055 (Mton $CO_2e$) | Reference Case | | | 27,552 | | |
| | Reference Case (w/ Lower Demands) | | | 24,433 | | |
| | Deep GHG Scenario (Low Biomass) | | | 16,671 | | |
| | Deep GHG Scenario (High Biomass) | | | 15,779 | | |
| | Deep GHG Scenario (No Nuclear or CCS) | | | 17,144 | | |
| | Deep GHG Scenario (Limited EV-FCV Success) | | | 15,761 | | |

Figure 82 and Table 49 both illustrate that total policy costs are lower in the Deep GHG High Biomass scenario than in the original Deep GHG Reduction Scenario (1.3% vs. 1.5% as a share of GSP, relative to the baseline), even though both scenarios achieve the same GHG reduction target of 80%. The average cost of carbon abatement is lower in the High Biomass scenario as well. The explanation for this finding is relatively straightforward: since, based on the assumptions for biomass used in this study, biofuels are a relatively inexpensive way to mitigate emissions in the transport sector – compared to electric and hydrogen vehicles and their requisite recharging/refueling infrastructure – greater biomass potential leads to reduced mitigation costs. Of course, it is none too clear that upwards of 13 billion gge of biofuels will be available to the California transportation fuels market in the future, especially if all other U.S. states and countries are also pushing for deep emission cuts (though it should noted that this analysis already builds this supposition into all the scenario storylines). The availability of biofuels may ultimately turn out to be lower than 13 billion gge, or even less than 8 billion gge as is the case in the Reference Case and the original Deep GHG Reduction Scenario. On the other hand, there is still a chance, albeit small, that total biofuels potential could be larger than this already high estimate. At this point in the time, the situation is none too clear. Biomass supply continues to be one of the greatest uncertainties in modeling low-carbon futures at all levels, whether for California, the U.S., or globally – hence the importance of conducting a sensitivity analysis on this critical issue.

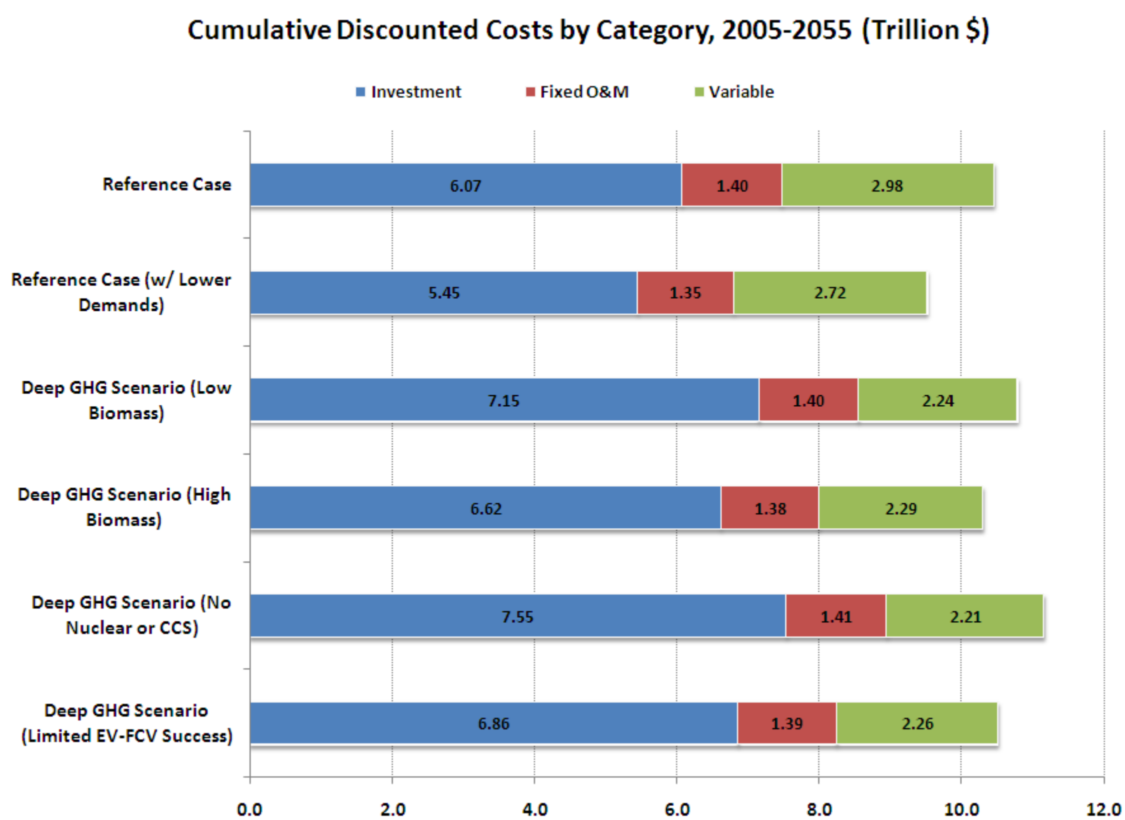


**Figure 82 Comparison of Cumulative Total Discounted Energy System Costs for Scenario Variants with Modified Resource and Technology Potentials**

**Table 49 Comparison of Key Cost Indicators for Scenario Variants with Modified Resource and Technology Potentials**

| Cost Indicators | | | Notes |
|---|---|---|---|
| **Cumulative Discounted System Costs, 2005-2055** | Reference Case | 9.8% | *Costs are relative to Reference Case (w/ Lower Demands)* |
| | Reference Case (w/ Lower Demands) | -- | |
| | Deep GHG Scenario (Low Biomass) | 13.3% | |
| | Deep GHG Scenario (High Biomass) | 8.2% | |
| | Deep GHG Scenario (No Nuclear or CCS) | 17.2% | |
| | Deep GHG Scenario (Limited EV-FCV Success) | 10.4% | |
| **Cumulative Discounted System Costs as a Share of Cumulative Discounted GSP, 2005-2055** | Reference Case | 1.5% | *Costs are relative to Reference Case (w/ Lower Demands)* |
| | Reference Case (w/ Lower Demands) | -- | |
| | Deep GHG Scenario (Low Biomass) | 2.1% | |
| | Deep GHG Scenario (High Biomass) | 1.3% | |
| | Deep GHG Scenario (No Nuclear or CCS) | 2.7% | |
| | Deep GHG Scenario (Limited EV-FCV Success) | 1.6% | |
| **Average Cost of GHG Abatement ($ per $tCO_2e$)** | Reference Case | -- | *Costs and GHGs are relative to Reference Case (w/ Lower Demands)* |
| | Reference Case (w/ Lower Demands) | -- | |
| | Deep GHG Scenario (Low Biomass) | 164 | |
| | Deep GHG Scenario (High Biomass) | 90 | |
| | Deep GHG Scenario (No Nuclear or CCS) | 225 | |
| | Deep GHG Scenario (Limited EV-FCV Success) | 114 | |

As in all the other scenarios and scenario variants discussed until now, the transportation sector, by far, comprises the lion's share of total capital investment costs (Figure 83). Electric sector investments are the second largest component, and it is this category that sees the largest cost increase in the No Nuclear or CCS scenario, which only achieves a 65% reduction in GHG emissions by 2050. This scenario is the most expensive of all the scenarios and variants discussed thus far, even more than the original Deep GHG Reduction Scenario with its 80% level of reduction. Lacking nuclear power and CCS as mitigation options, the model is forced to invest in an even greater amount of out-of-state wind and solar power, an action that requires significant investments in transmission lines in order to bring these renewable resources into the California market from their often distant locations.

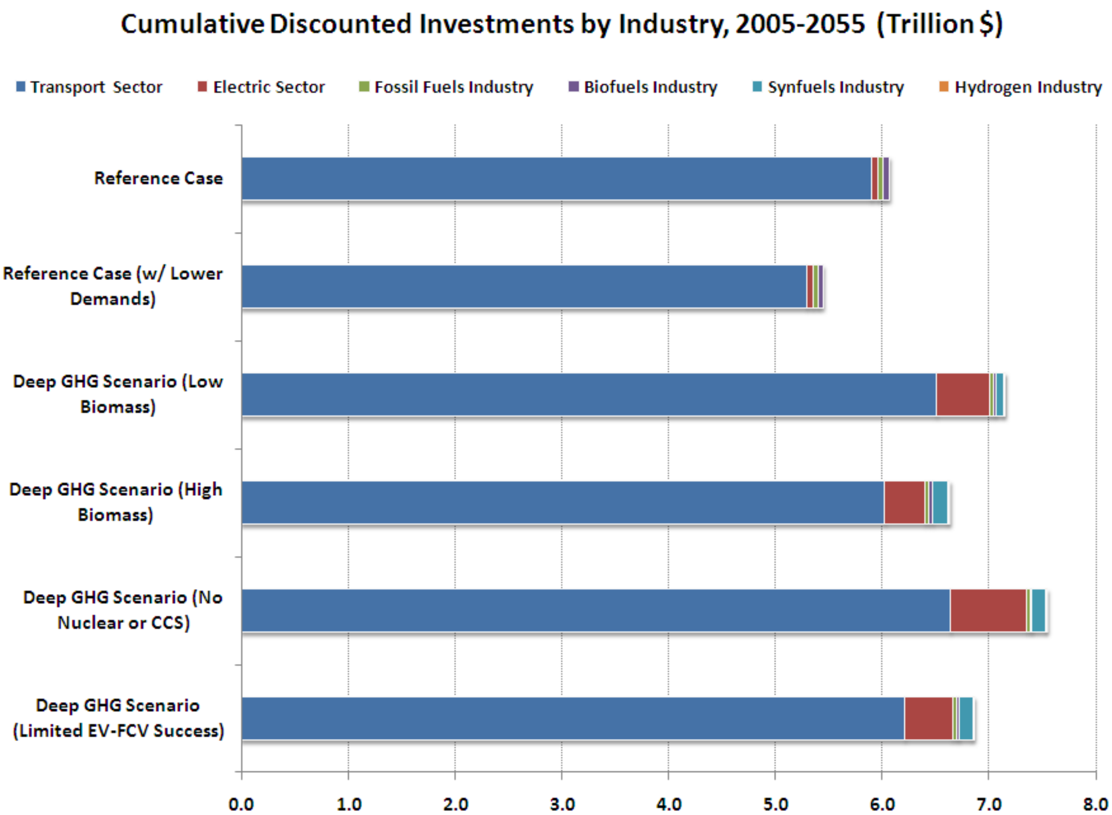


**Figure 83 Comparison of Cumulative Discounted Energy Investments for Scenario Variants with Modified Resource and Technology Potentials**

## II.4 Conclusions

The specter of climate change looms large as one of the most critical global issues to address in the twenty-first century. Its varied impacts are likely to be felt in California in a very direct way, and for this reason the state has taken important, initial steps over the past several years to enact a suite of policies that will ultimately reduce its contribution of greenhouse gas emissions. California's current energy and climate policies (e.g., emissions trading program, renewable portfolio standard for electricity, vehicle efficiency and emissions standards, low carbon fuels standard) tend to have a near-term time horizon of 2020 and are fairly modest in their level of stringency. Yet, they will nevertheless have a worldwide effect since climate change is a global phenomenon. While making an important contribution to U.S. and global mitigation efforts, the policies will undoubtedly provide a solid foundation for transitioning to a lower-carbon economy. In the long term, however, it is clear that far greater reductions will ultimately be required – not only in California but worldwide – to keep global temperature change to below 2º C over the course of this century, which the science indicates is necessary in order to avoid the most destructive impacts of climate change (IPCC, 2007). To this end, California has an aspirational goal of reducing its GHG emissions 80% below 1990 levels by 2050. Such a target would necessitate a dramatic transformation in how energy is produced and consumed within the state – an "energy revolution" in the truest sense of the phrase.

The overarching challenge is that the technology and policy options for making a dramatic energy transformation are not well enough understood at the present time, and in addition the (publicly-available) tools for modeling this kind of transition at the level of California's entire energy system have been, to date, rather limited. The analysis described in this dissertation chapter has attempted to fill this void by developing an energy-engineering-environmental-economic (4E) systems optimization model to represent the vast majority of energy and emission flows within, to, and from California. The CA-TIMES model, as it is called, is built within the well-established MARKAL-TIMES framework and is, thus, extremely rich in bottom-up technological detail. The main application of the model is to develop scenarios for how California's energy system could potentially evolve over the next several decades, in light of strong policies to reduce energy use and greenhouse gas emissions. With a few notable exceptions, most technologies and policies can be represented within CA-TIMES.

A variety of scenarios have been developed in this analysis, ranging from a business-as-usual Reference Case to a Deep GHG Reduction Scenario, in which a mixed-strategy, portfolio approach allows California emissions to be reduced 80% below 1990 levels by 2050. Several variants of the Deep GHG scenario are then also developed, in order to explore important sensitivities related to the stringency of the emissions cap (i.e., less stringent than an 80% reduction) and the ultimate potential of key resources and technologies to contribute to greenhouse gas mitigation (e.g., sustainable biomass supply, nuclear power, carbon capture and storage, and electricity and hydrogen as transportation fuels).

In sum, this analysis shows that deep reductions on the order of 50% to 80% appear to be technically feasible at reasonable costs (e.g., 1.0% to 2.7% of California Gross State

Product over the 2005-2055 time period, relative to the baseline scenario – only considering the transportation, electricity, and fuel conversion sectors). Policy cost estimates of this magnitude are in line with those of other studies for decarbonization of the U.S. and global energy systems (IEA, 2010; NRC, 2010). The bulk of the costs would be incurred in the medium to long term (between 2025 and 2050), as increasingly advanced technologies are used to make deeper and deeper reductions. The challenge for policy, however, is perhaps the next ten years (2010-2020). This analysis shows that whether policymakers ultimately decide to pursue a reduction target of 80% or something much less stringent (say, 50%), the types of technologies that need to be introduced in the near term are for the most part the same; hence, the emissions trajectories up to 2025 would be fairly similar. Furthermore, results of this study indicate that California's current target for 2020 – the AB32 goal of bringing emissions back down to 1990 levels – may not be stringent enough. To allow time for significant market penetration of the kinds of transformational technologies that will be needed in the long term (due to the inertia of energy system infrastructure and investments), advanced technologies must be introduced over the next ten years at a quicker rate than what the existing 2020 target is likely to motivate. More specifically, over the coming decade a significant expansion in, or at least the introduction of, the following mitigation options are likely needed: renewable electricity generation, specifically from wind, solar, and geothermal resources; advanced transportation technologies and fuels, including biofuels, hybrid-electric vehicles, plug-in hybrid electric vehicles, battery-electric vehicles, and hydrogen fuel cell vehicles; and a shift toward greater utilization of electricity as an end-use fuel in the industrial, commercial, residential, and agricultural sectors. Demand reduction is also likely to play an invaluable role in mitigating future emissions, both through energy efficiency and conservation efforts and reduced vehicle travel. The latter, which could be achieved by strong transit, land use, and auto pricing policies, deserves a considerably more attention in the development of energy and climate scenarios for California.

At the present time, it is not exactly clear what a declining cap on GHG emissions after 2020 would actually cover, if such targets were ever to be codified into law. The existing 2020 cap excludes emissions from interstate and international aviation and marine activities. However, because this emissions category is fairly large and growing quickly, I have decided to include it in the emissions caps envisioned by the scenarios in this analysis. After all, in reality these emissions would somehow have to be covered, no matter which entities have jurisdiction over them. Perhaps they might be included in a federal emissions cap, or maybe the international component of the emissions could be dealt with under the auspices of the International Civil Aviation Organization (ICAO) or the International Maritime Organization (IMO) (McCollum et al., 2009). Either way, the emissions must ultimately be controlled, and advanced technologies and fuels will be required for this purpose. While CA-TIMES is not able to explicitly model the impact of policies enacted outside of the California energy system, it is nevertheless important to capture the fuel use and investment decisions that might be made in these important transport segments if such policies were in place. Of course, had emissions from interstate and international aviation and marine transport not been included in the scenarios developed in this study, it would certainly have been a bit easier and cheaper to achieve the 50-80% reduction targets.

In terms of decarbonizing California's energy system, the transportation sector poses perhaps the biggest challenge and is therefore the most costly. Over half of the state's GHG emissions are attributable to transport at present, resulting primarily from the combustion of fossil fuels (gasoline, diesel, jet fuel, and residual fuel oil). Of course, because fossil fuels are relied upon so heavily, the potential for reducing transport GHGs via alternative fuel and vehicle technologies is quite huge. Biofuels are the most cost-effective option for making these emission cuts, both from the perspective of a single vehicle or when viewed at the energy systems level, the latter including fuel production and distribution infrastructure and considering competition for biomass from other sectors, such as electric generation and industry. The challenge with biomass is that total resources, while renewable on an annual basis, are actually rather limited. Only if California were to have access to biomass supplies far beyond its "fair share" of the national or global total (e.g., >30% of all U.S. consumption), would the state be able to fuel its entire transport sector with biofuels. This is perhaps unlikely in a future where other U.S. states and countries are also counting on biomass/biofuels to mitigate their GHG emissions. Given constraints on biomass resources, the results of this analysis indicate that the most optimal use of biofuels is in the non-light duty subsectors, namely in the form of bio-derived gasoline, diesel, jet fuel, and residual fuel oil. The reason for this is fairly intuitive: there are fewer alternative technological/fuel options to reduce GHG emissions in these other transport subsectors, hence the value of a tonne of biomass is higher. In fact, a marked advantage of light-duty vehicles is that there are quite a few alternatives for technology- and fuel-switching. Specifically, electric-drive vehicles could feasibly be used to satisfy a large portion of total VMT demand, whereas electricity and/or hydrogen are simply not realistic alternatives in some of the other subsectors, due to range limitations and refueling issues. The GHG reduction scenarios developed here rely heavily on HEVs and PHEVs (Gasoline and E-85), as well as Hydrogen FCVs to some extent, to make deep emission cuts in the light-duty subsector. In contrast, BEVs do not penetrate the LDV market to any significant degree, a result that may have more to do with model dynamics than anything else. BEVs are not favored by the model because of the various inputs that are currently assumed for the efficiencies and costs of vehicles and plug-in recharging infrastructure. The assumed costs for BEVs, for instance, are higher than for other advanced vehicle technologies because, in an effort to be fair, all vehicles in CA-TIMES are assumed to have roughly the same size, weight, range, power, etc. While this aggregated level of vehicle class representation for the most part makes sense within the modeling framework, it potentially disadvantages BEVs, which may be particularly well suited to the small car and small light truck markets or to urban driving, where travel distances are shorter. The current version of CA-TIMES is not able to capture this possibility, though future work may attempt to address this issue.

As the transport sector is decarbonized, emissions from the energy supply/conversion sector are likely to be reduced significantly as well, since the types of facilities that produce low-carbon transport fuels (e.g., bio-refineries, FT syn-fuels poly-generation plants, hydrogen plants, zero- and low-carbon electricity generation) tend to emit low levels of greenhouse gases, or at least they would in a low-carbon future. The exact carbon signature of these fuels, of course, depends on which energy resources are used for generating heat and electricity at these plants, and also whether or not carbon capture and storage is utilized. Bio-CCS technologies appear to be an especially attractive means by which to decarbonize the energy system, since they allow for negative emissions (i.e., permanently storing biomass carbon underground). In the scenarios developed in this study, bio-CCS play a major role in reducing GHG emissions while at the same time taking the burden off of other sectors, namely transport, which have higher abatement costs. When bio-CCS technologies are eliminated from the potential technology portfolio, however, the transport sector is forced to decarbonize much more significantly, and in the light-duty sector in particular, more advanced electric-drive vehicles (PHEVs and Hydrogen FCVs) become a preferred option for making these emissions cuts.

Emissions from the industrial, commercial, residential, and agricultural (ICRA) end-use sectors are reduced in this study through energy efficiency and fuel switching. In particular, drawing on other scenario studies by the IEA (2010), the Deep GHG Reduction Scenario assumes that an increasing share of energy demand is met by electricity and natural gas in the ICRA sectors in the future. How authentic these emission reductions actually are depends in large part on the simultaneous decarbonization of the electric sector, which also appears to be a likely outcome of stringent climate policy, as found in this and numerous other studies.

Comparatively, reducing emissions from electric generation is fairly straightforward and can be done at abatement costs that are lower than in the transport and energy supply sectors (IEA, 2010). Nonetheless, significant hurdles still remain, particularly with respect to spatial and temporal issues. For example, it could potentially be quite expensive to tap solar, wind, and geothermal resources in distant out-of-state locations, owing to the substantial capital investments required for long-distance transmission lines. In addition, it is still not entirely clear whether intermittent renewables, especially solar and wind, can be relied upon to contribute a majority share of total electric generation, unless significant storage and/or back-up capacity is built as well. For these reasons, the availability of nuclear power and fossil and/or biomass CCS is critical, so that low-carbon options for baseload generation remain in play. If nuclear and CCS are wholly absent from the technology portfolio, as one variant of the Deep GHG Reduction Scenario illustrates, then it will likely become considerably more difficult, and indeed more costly, to achieve a deep reduction target, if it is even possible. Other scenario variants lead to similar conclusions when biomass resources are significantly constrained or when the potential for electricity and hydrogen to be used in the transport sector is considerably limited.

An important caveat to this analysis is that it only does a partial economic accounting. In other words, it attempts to capture the total energy system *costs* of climate mitigation but largely ignores the significant economic *benefits* of pursuing this goal. For instance, the analysis does not consider the avoided costs (i.e., benefits) of climate change (e.g., more frequent extreme weather events, impacts on global agriculture and food production) or of climate adaptation (e.g., construction of sea walls, relocation of coastal populations). Similarly, the benefits accruing from reduced health expenditures and increased life expectancies, to the extent they can attributed to climate mitigation, have not been monetized here. Given this partial accounting, it is highly likely that the cost figures shown in this chapter are somewhat overestimated, a practice that is a known issue with integrated assessment models used to inform energy and climate policymaking (Nemet et al., 2010).

Like any study, this one has probably created more questions than it has answered. (At least that should be the goal of good research in my opinion.) And for this reason a number of issues must be left for future work. These issues have already been discussed in the appropriate sections of the text, but they are summarized again here. First, and probably foremost, the level of technological detail in the ICRA end-use sectors must be improved. Even though they account for only 15% of current fuel combustion-related emissions in California, it is still important to understand the fuel use and investment decisions that might be made in these sectors under stringent climate policy. Then, once this model improvement has been made, it would be very interesting to look more deeply into the timing of electricity supply and demand, specifically with respect to the intermittency of renewables, electric vehicle recharging, and “smart” appliances. In terms of behavioral changes and transport demand reduction, the development of more sophisticated low-VMT scenarios is probably desirable, if possible harnessing the capabilities of travel demand modeling experts, such as those in the UC-Davis Urban Land Use and Transportation (ULTRANS) Center. At the same time, our group would like to be able to explicitly model transport mode-switching (i.e., between LDVs and transit buses/rail) and also class-switching within particular subsectors (i.e., between compact, small, mid-size, and large cars). Such endogenous representation of consumer behavior in the transport sector is not a common feature of typical energy systems models, despite its obvious importance. Therefore, it could be a ripe area for research. Other ideas for future research include bringing endogenous technological learning (ETL) into the model for certain key technologies (e.g., fuel cells, batteries, solar, wind, nuclear, IGCC, CCS) and better representing the staged development of vehicle refueling infrastructure (namely biofuels, hydrogen, and electricity). In the latter case, our group plans to draw upon previous work by other UC-Davis STEPS Program researchers, such as Yang and Ogden (2007) for hydrogen and Parker (2010) for biofuels. The CA-TIMES model would also be substantially improved if the emissions accounting framework were overhauled so that dynamic lifecycle analyses could be conducted, thereby making it possible for policies such as an LCFS to be explicitly and endogenously represented. Lastly, although they account for only 11% of California's total emissions at the present time, non-energy greenhouse gases also need to be accounted for in the modeling framework, even if there are no technologies in the model that are able to reduce them.

## II.5 Acknowledgements

I have many people and organizations to acknowledge for the success of the CA-TIMES project up to this point. For funding this portion of my dissertation work, I would like to thank the Sustainable Transportation Energy Pathways (STEPS) Program at the University of California-Davis, Institute of Transportation Studies, as well as the Achievement Rewards for College Scientists (ARCS) Foundation, private fellowship support of Mr. Ernest E. Hill, and California Air Resources Board. In addition, the research was supported by a grant from the Sustainable Transportation Center at the

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Without all of this generous help, this initial version of the CA-TIMES model would have never come to fruition. Looking back, I can honestly say that I had no idea what I was getting into when I started this project almost three years ago. Building an energy

systems model from scratch is an incredibly exhaustive, time-consuming, and sometimes frustrating process. But it is also one of the most broadly educational experiences I can possibly imagine for a Ph.D. dissertation in such an interdisciplinary subject as energy, transportation, and climate change.

# PART TWO

# RESEARCH STREAM #3

## III. Exploring synergies and trade-offs between global energy objectives: Near-term energy security and air pollution goals and mid- to long-term climate targets (IIASA collaboration)

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**Abstract:**

The energy system of the future could potentially develop along a number of different paths, depending on how society and its decision makers prioritize various, worthwhile energy objectives, including: climate change mitigation; access to affordable, reliable energy for healthy socio-economic growth; energy security; reduced air and water pollution and human health impacts; minimization of ancillary risks such as nuclear waste and proliferation; and alleviation of global poverty. These objectives are generally discussed in the context of different timeframes (e.g., security and pollution/health in the near term; climate in the medium to long term). Therefore, they frequently compete for attention in the policy world. The work described in this chapter summarizes the findings of a unique study conducted at the International Institute for Applied Systems Analysis

(IIASA) in support of the Global Energy Assessment, in which global energy and climate scenarios are used to illuminate some of the key synergies, and to a lesser extent the trade-offs, between climate mitigation, energy security, air pollution and human health impacts, and affordability. Two tools are jointly utilized in this project: a systems engineering global energy model (MESSAGE) and a global climate model (MAGICC). In sum, a wide array of plausible energy futures are generated and analyzed, in order to understand the potential evolution of the global energy system, and the subsequent climate system response, over the twenty-first century, under varying assumptions for energy security, air pollution, and greenhouse gas emissions. Each of these scenarios looks different, in both its inputs and outputs, and on a sliding scale of satisfaction, each meets the different energy system objectives to varying degrees. Analysis of this large ensemble of scenarios leads to several important conclusions. First, the synergies between the various objectives far outweigh the trade-offs. The principal trade-offs center around, on the one hand, the reduction of certain climate-cooling air pollutant emissions, which can have an important impact on the global climate by leading to increased radiative forcing; and on the other hand, the enactment of virtually any significant climate, air pollution, and/or energy security legislation, which is likely to have a non-zero policy cost relative to a no-policy, business-as-usual baseline scenario. That being said, when viewed from an holistic and integrated perspective, the combined costs of climate mitigation, energy security, and air pollution control come at a significantly reduced total energy bill if the multiple benefits of each are properly accounted for in the calculation of total energy *system* costs (i.e., when taking a systems view of the problem). Second, zero-carbon energy technologies, particularly biomass and other renewables, appear to be especially attractive, robust options for achieving the various objectives because they are able to contribute to virtually all sustainable development goals simultaneously.

## III.1 Introduction

The energy challenges facing society are as varied as they are great. And if sustainability is truly the end goal, then any future energy system would achieve a number of different objectives: climate change mitigation; access to affordable, reliable energy for healthy socio-economic growth; energy security; reduced human health impacts; reduced air and water pollution; minimization of ancillary risks such as nuclear waste and proliferation; and alleviation of global poverty.[53] In an ideal world, it would be possible to simultaneously meet each of these important aspirations; however, when considering constraints on resources and on financial, human and political capital, as well as the long turnover times that characterize the energy industry and energy end-use sectors, the challenge inherent in this proposition becomes abundantly clear. What is more, the prioritization of the multiple objectives is not shared equally by all stakeholders (individuals, firms, and governments), and at times the objectives are in conflict with one another and compete for attention. In addition, the time horizons envisioned for meeting the different objectives are quite varied. For example, while energy security and pollution reduction (i.e., improved global health) are discussed as near-term goals (2010-2030), climate change is, generally-speaking, more of a long-term problem (2030-2050 and beyond).

The work described in this dissertation chapter was conducted as part of the Global Energy Assessment (GEA), a major initiative seeking to redefine the global energy policy

[53] Incredibly, some two billion in the developing world currently lack access to affordable modern forms of energy.

agenda.[54] Coordinated by the International Institute for Applied Systems Analysis (IIASA) with contributions from more than 200 scientists from a range of disciplines and countries, this multi-year and multi-stakeholder activity, scheduled to be published in early-2011, aims to help decision makers address the challenges of providing energy services for sustainable development throughout the world. The GEA will examine trade-offs and synergies between energy objectives and identify robust energy strategies and scenarios that contribute to all development goals simultaneously.

In my dissertation research, I focus specifically on trade-offs and synergies between near-term energy security and air pollution/health goals, mid-term greenhouse gas reduction targets, and long-term climate system impacts. Two tools are jointly utilized in order to study these interactions using scenario analysis: a systems engineering global energy model (MESSAGE) and a global climate model (MAGICC). This methodology is discussed in more detail in the sections that follow. I have collaborated extensively with IIASA researchers, in order to carry out this analysis. This collaboration has culminated in two distinct products: 1) a chapter of my dissertation, and 2) a section of the scenarios chapter of the GEA report.

The motivation for this study derives directly from the global energy and climate policy agenda. Climate change has become a core issue at the international level over the past several years. In 2009, the Group of Eight (G8) industrialized nations agreed to reduce global GHG emissions 50% below 1990 levels by 2050, with the intent to hold global

[54] For more information on the Global Energy Assessment, see the following URL: http://www.iiasa.ac.at/Research/ENE/GEA/index.html.

warming to less than 2 degrees Celsius above pre-industrial levels (G8, 2009). The Copenhagen Accord later affirmed the 2 ºC target. This level of warming is what many scientific studies suggest is necessary to achieve in order to avoid the most destructive impacts of climate change (IPCC, 2007). Energy security, on the other hand, is quite a different issue, though as this paper shows, pushing the security objective could have a potentially significant impact on the global climate. For the most part, energy security is an issue of concern at the level of individual nations or groups of nations (e.g., the European Union), and the time horizon of interest is nearer to the present than that which is being discussed for climate mitigation (2020-2030 vs. 2020-2050). In addition, energy security goals are much less well-defined than climate targets – something that creates a challenge from a modeling perspective – and while the concept of energy security is widely discussed, its definition is vague, and there is no consensus as to its precise interpretation (Kruyt et al., 2009). Security can be measured in several ways, for example, through diversity of supply (with respect to resources and/or trading partners); reduced energy imports and, consequently, increased domestic production; and/or an attempt to dampen volatile price swings. In the United States, much of the policy discussion centers on reducing imports of foreign oil, though security of natural gas supplies and the reliability of electricity supply systems have also captured the attention of policymakers (Yergin, 2006). In Europe, the discussion is similar, except that imported natural gas appears to be the main concern (EU, 2008). Finally, the United Nations Millennium Development Goals (MDG) include, in part, the improvement of human health (United Nations, 2010), and since air pollution (both indoor and outdoor) is an important contributor to child and adult mortality, especially in the developing world, the benefits to reducing pollution from the energy system are potentially significant (Amann, 2009; Cofala et al., 2010; Cofala et al., 2009).

Few published studies have analyzed trade-offs and synergies among multiple energy objectives. Perhaps the most comprehensive study to date was that which was carried out under Research Stream RS2b of the European Union Integrated Project NEEDS (New Energy Externalities Developments for Sustainability) (Schenler et al., 2009). In this project researchers compared 26 future (year 2050) electricity generation technologies (e.g., nuclear, solar, advanced coal) in four European countries across 36 different environmental, economic, and social metrics. Then, stakeholder preferences were surveyed and the relative sustainability and robustness of different technologies were evaluated. The central conclusion of the study is that an individual's unique preference profile for a range of sustainability criteria has a critical influence on the technology that is considered "best" or "optimal". The study also finds that future renewable energy technologies are generally attractive, fairing well across all dimensions (environmental, economic, and social), whereas the overall attractiveness of nuclear and fossil technologies depends strongly on the emphasis placed on environmental performance and/or social acceptance (Schenler et al., 2009).

Similarly, Jacobson (2009) reviews twelve different technological solutions (combinations of energy sources and vehicle types) to a range of energy and environmental challenges and compares them across multiple criteria and externalities, including global warming, air pollution mortality, and energy security, as well as their impacts on water supply, land use, wildlife, resource availability, reliability, thermal pollution, water pollution, nuclear proliferation, and undernutrition. Each vehicle-fuel combination is ranked and weighted with respect to these impact categories. The study finds that, among the technologies considered, four tiers emerge from the rankings, with wind-powered battery-electric vehicles and wind-powered hydrogen fuel cell vehicles the most attractive technology combinations, followed closely by several of the other renewably-powered BEV combinations (e.g., concentrated solar power, solar photovoltaic, geothermal, tidal, and wave). Nuclear power, coal with carbon capture and storage, and flexible fuel vehicles powered by corn-based and cellulosic ethanol fair the worst in the author's analysis.

Martinsen and Krey (2008) carry out an analysis somewhat similar to ours in the sense that future energy scenarios, rather than single energy technologies, are analyzed and compared based on their ability to achieve a range of energy objectives. They introduce fuzzy (or soft) constraints to a bottom-up, myopic energy optimization model for Germany, IKARUS, and use their framework to "obtain a better representation of political decision processes" by finding compromises between competing energy objectives (e.g., environment, economy, security, and nuclear phase-out). A key conclusion of the study is that while some policy targets are contradictory, others push in the same direction, an obvious example of which is the reduction of GHG emissions and a renewable portfolio standard (minimum share of renewables in total electricity supply). The authors also suggest that hard constraints (i.e., those typically used in energy systems models) may have an unjustifiably strong impact on the model solution, hence the need for using soft constraints in combination with multi-objective optimization (Martinsen and Krey, 2008). For those interested, Rommelfanger (1996) surveys the methods for solving linear programming (LP) models with soft constraints and reviews several applications, while Oder et al. (1993) and Canz (1998) provide examples of how fuzzy LP can be applied to energy systems models.

Other studies – specifically Meinshausen et al. (2009) and O'Neill, Riahi, et al. (2010) – have explored the relationship between mid-century global GHG targets and long-term climate system outcomes, research that builds upon other major works found in the literature – e.g., Nakicenovic and Swart (2000), Keppo et al. (2007), and Van Vuuren et al. (2008). These studies develop probabilistic estimates of climate system impacts (e.g., atmospheric $CO_2$-eq concentrations and global-mean surface temperature increase) based on an assortment of emissions trajectories. The research described in this dissertation chapter contributes to this diverse body of literature, encompassing the fields of energy modeling, energy and climate policy, and climate change science. It then goes beyond these studies by also considering energy security and air pollution. Notably, both Meinshausen et al. (2009) and O'Neill, Riahi, et al. (2010) employ essentially the same reduced complexity coupled global climate-carbon cycle model, MAGICC, that I am using in my dissertation research, MAGICC. The only difference is that the modified version of MAGICC that I use is also able to account for the climate impacts of black and organic carbon, which is important in my case since I am evaluating the trade-offs between, and co-benefits from, climate change mitigation and reduced air pollution. In addition, I employ the same model of the global energy system, the IIASA MESSAGE integrated assessment modeling framework, that O'Neill, Riahi, et al. (2010) use in their analysis.

Meinshausen et al. (2009) estimate the probability of exceeding maximal warming levels (namely the G8's 2 ºC target) using a set of 26 IPCC SRES and 20 EMF-21 scenarios (Nakicenovic and Swart, 2000; Van Vuuren et al., 2008), as well as 948 additional equal quantile walk emission pathways, which are developed by the authors. This large set of multi-gas mitigation scenarios represents a wide range of plausible 21$^{st}$ century GHG emissions trajectories – from scenarios where early action is taken to scenarios where action is delayed, the emissions peak comes later, and emissions then rapidly decline thereafter. Importantly, only one of these scenarios assumes the possibility of negative fossil $CO_2$ emissions later in the century. In using the MAGICC climate model, Meinshausen et al. (2009) vary several dozen climate response and other key model parameters (based on 19 different probability distributions for the important parameter of climate sensitivity), in order to estimate the probability of exceeding 2 ºC warming both as a function of cumulative GHG emissions over the first half of the twenty-first century and of annual emissions in 2050. Under the mitigation scenarios used, a 50% reduction of global GHG emissions below 1990 levels by 2050 would lead to a 12 to 45% probability of exceeding 2 ºC warming (i.e., a 55 to 88% probability of staying below 2 ºC).

O'Neill, Riahi, et al. (2010) conduct an analysis similar to that of Meinshausen et al. (2009), exploring the relationship between mid-century GHG targets and long-term climate system outcomes. In order to estimate the probability of staying below 2 ºC warming (over pre-industrial temperatures) based on a range of GHG emissions trajectories, the reduced complexity climate model, MAGICC, is run stochastically, varying several key climate system parameters per probability density functions found in the literature,. In addition, rather than relying on other mitigation scenarios found in the literature, as is the case in the Meinshausen et al. (2009) study, the authors use a model of the global energy system with detailed technological representation (the IIASA MESSAGE integrated assessment modeling framework). This allows the authors to look at scenarios with negative annual GHG emissions later in the century (e.g., through biomass carbon capture and storage), which allows for delayed mitigation action and a later peak in global emissions, while still retaining a realistic probability of achieving the 2 ºC target. Also, by explicitly capturing inertia and path dependency in the energy system (e.g., rates of capital stock turnover, limits to market penetration rates of particular technologies, and relationships between production and distribution systems), the authors are able to estimate "feasibility thresholds" – i.e., the conditions that must be present in 2050 in order to preserve the possibility of meeting certain long-term climate targets. An important illustrative result is that, assuming a medium energy demand scenario (e.g., a B2 storyline), if global average temperature change over the course of the century is to be kept below 2 ºC with 50% probability or greater, then global annual GHG emissions in 2050 must be at least 20% below 2000 levels. Failing to reach the 20% reduction target by mid-century would significantly hamper the ability of meeting the long-term target because of the inability to invest in low-carbon technologies quickly enough in the second half of the century.

## III.2 Methodology

This project brings together two distinct modeling tools into a cohesive framework. Both are described more fully in the sections that follow.

1) **MESSAGE** (Model for Energy Supply Strategy Alternatives and their General Environmental Impact), a global systems engineering optimization model used for medium- to long-term energy system planning, energy policy analysis, and scenario development (Messner and Strubegger, 1995)
2) **MAGICC** (Model for the Assessment of Greenhouse-gas Induced Climate Change) version 5.3, a reduced complexity coupled global climate-carbon cycle model, which calculates internally consistent projections for atmospheric concentrations, radiative forcing, global annual-mean surface air temperature, and sea level rise (Wigley, 2008)

### *III.2.1 Systems Engineering Global Energy Model (MESSAGE)*

The MESSAGE integrated assessment model is an evolving framework that has been developed at the International Institute for Applied Systems Analysis (IIASA) for more than two decades (Messner and Strubegger, 1995). Like other global energy models in its class (e.g., AIM, EPPA, IMAGE, IPAC, and MiniCAM), MESSAGE has gained recognition over time via its repeated utilization in developing global energy and emissions scenarios, especially its use in previous IPCC reports (e.g., see Nakicenovic and Swart (2000)).

MESSAGE is an 11-region global energy model (Figure 84) which attempts to represent the world's energy system with all its interdependencies from resource extraction, imports and exports, conversion, transport, and distribution, to the provision of energy end-use services such as light, space conditioning, industrial production processes, and transportation. Trade flows (imports and exports) between regions are monitored, capital investments and retirements are made, fuels are consumed, and emissions are generated. In addition to the energy system, the model includes also the other main greenhouse-gas emitting sectors, agriculture and forestry. MESSAGE tracks a full basket of greenhouse gases and other radiatively active gases – $CO_2$ , $CH_4$ , $N_2O$ , $NO_x$ , volatile organic compounds (VOCs), CO, $SO_2$, PM, BC, OC, $NH_3$, $CF_4$, $C_2F_6$, HFC125, HFC134a, HFC143a, HFC227ea, HFC245ca, and $SF_6$ – from both the energy and non-energy sectors (e.g., deforestation, livestock, municipal solid waste, manure management, rice cultivation, wastewater, and crop residue burning). In other words, all Kyoto gases plus several others are accounted for.

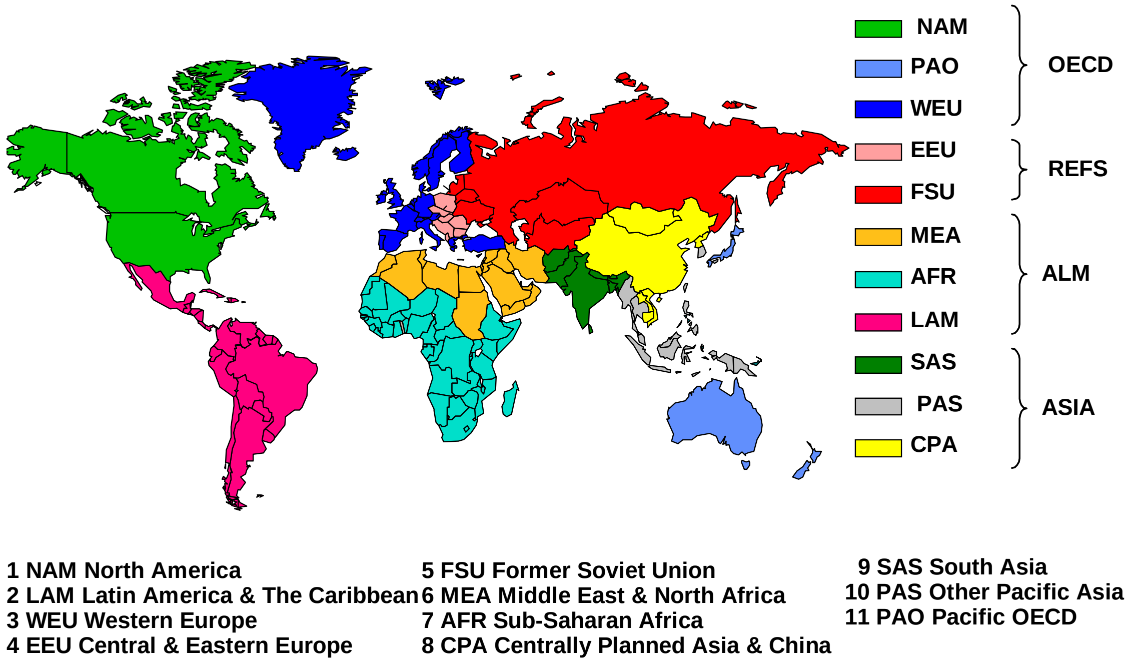


**Figure 84 Map of 11 Regions in MESSAGE Model**
**(for a list of countries by region, see the appendix)**

Similar to the MARKAL-TIMES modeling framework (described in Chapter II), MESSAGE is a linear programming model, in which optimization is performed by minimizing total discounted energy system costs over the entire model time horizon (1990-2110). All primary energy resources are characterized by supply (cost) curves, and all energy technologies are characterized by investment, variable, and O&M costs. Energy prices are calculated endogenously, and investment decisions and fuel choices are made based on the least-cost decision-making principle, subject to constraints (both technical and policy), thus reflecting a perfectly functioning global energy market, to the extent possible. The model is able to choose between both conventional and non-conventional technologies and fuels (e.g., advanced fossil, nuclear fission, biomass, and renewables). Obviously, the selection of technologies/fuels available to the model has an important effect on the model result. In the version of the model used in this paper, we consider a portfolio of technologies whose components are either in the early demonstration or commercialization phase (e.g., coal, natural gas, oil, nuclear, biomass, solar, wind, hydro, geothermal, carbon capture and storage, and hydrogen). Notably, this includes bio-CCS, a technology that can potentially lead to negative emissions (permanent underground storage of $CO_2$ that was originally pulled out of the atmosphere by photosynthesis). Nuclear fusion and geo-engineering options, however, are not included in the current version of the MESSAGE model.

Price-induced changes in energy demand (i.e., elastic demands) are also modeled in our version of MESSAGE. In short, we use an approach, similar to that described in Messner and Schrattenholzer (2000), which systematically assesses regional conservation costs for different levels of prices and demand. For each of the eleven MESSAGE regions, we estimate a conservation cost (i.e., demand response) curve for each of the six end-use demands. These curves are meant to represent energy conservation and efficiency improvements in each region. Put simply, a specified quantity of demand reduction can be achieved at a particular cost. The quantity and cost steps for each of these curves are generated via a multi-stage iterative solution process between MESSAGE and a top-down, macro-economic model of the global economy.[55] This integrated modeling

[55] Development of the conservation cost curves (CCCs) is relatively straightforward in practice. First, we run a baseline scenario and a set of five stabilization runs using the integrated MESSAGE-MACRO modeling framework. After several iterations of a given run, the two models reach convergence, and at that point the demand responses in each region are in equilibrium with the price increases resulting from a carbon constraint (or any other energy-related constraint that causes prices to increase or decrease, i.e., an energy security constraint). Once the six MESSAGE-MACRO runs have been completed (baseline + five stabilization runs), we obtain CCCs for each of the six end-use demands in each region. The equilibrium prices from the five stabilization runs are used directly as costs for the conservation steps, because these

framework is known as MESSAGE-MACRO (Messner and Schrattenholzer, 2000) and only needs to be run once, since the five-step demand response curves that are generated can subsequently be used in all of our non-MACRO model runs. Such a procedure substantially reduces total computing time, when compared to the alternate method of solving MESSAGE-MACRO iteratively for every single scenario, and for this reason several recent studies have utilized this simplified demand response methodology (Keppo and Strubegger, 2009; Krey and Riahi, 2009; O'Neill et al., 2010). Note that the demand-side conservation costs derive from the elasticities in the macro-economic model, and these costs represent both technological and behavioral measures for achieving energy efficiency and conservation, while considering the substitutability of capital, labor, and energy as inputs to the production function at the macro level. In this sense, demand reduction due to behavioral change is monetized in a way similar to technology-related costs. In essence, the conservation costs derived from the macro model represent the costs that society would be willing to bear to bring demand and prices into equilibrium. They do not, however, include macro-economic costs (e.g., GDP, welfare, and consumption losses).

Further and more detailed information on the MESSAGE modeling framework is available, including documentation of model set-up and mathematical formulation (Messner and Strubegger, 1995) and the model's representation of technological change and learning (Rao et al., 2006; Riahi et al., 2004; Roehrl and Riahi, 2000).

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price levels trigger the demand response. The differentials between the six demand levels (for each of the six demands per region) represent the corresponding sizes of the steps.

### *III.2.2 Global Climate Model (MAGICC)*

MAGICC is a reduced complexity coupled global climate-carbon cycle model, in the form of a user-friendly software package that runs on a personal computer. The standard version of MAGICC (v5.3) calculates internally consistent projections for atmospheric concentrations, radiative forcing, global annual-mean surface air temperature, ice melt, and sea level rise, given emissions trajectories of a range of gases ($CO_2$, $CH_4$, $N_2O$, CO, $NO_x$, VOCs, $SO_2$, and various halocarbons, including HCFCs, HFCs, PFCs, and $SF_6$) (Wigley, 2008). For this analysis, a modified version of MAGICC v5.3 was used, which allows for an explicit treatment of black and organic carbon (BC and OC).[56] The time horizon of the model extends as far back as 1750 and can make projections as far forward as 2400. The climate model in MAGICC is an upwelling-diffusion, energy-balance model, which produces output for global- and hemispheric-mean temperature and for oceanic thermal expansion. Climate feedbacks on the global carbon cycle are accounted for through the interactive coupling of the climate model and a range of gas-cycle models. The primary developer of MAGICC is Dr. Tom Wigley at the National Center for Atmospheric Research in the United States. The modeling package has been used in all IPCC Assessment reports, dating back to 1990; its strength lies in its ability to replicate the more complex global climate models, which run on supercomputers. For our analysis, we use a version of the software that is consistent with the IPCC Fourth Assessment Report, Working Group 1.

[56] I gratefully acknowledge Dr. Steve Smith of the Pacific Northwest National Laboratory (USA) for sharing a modified version of MAGICC (v5.3), which takes user-specified trajectories of BC and OC as inputs.

In contrast to how MAGICC is typically used, I run the model stochastically in order to generate probabilistic estimates of climate system responses (e.g., temperature increase or atmospheric GHG concentrations), a methodology first described in Keppo et al. (2007). Whereas a typical user of MAGICC, who is interested in generating (deterministic) point estimates of climate system responses, would run the user-interface version of the model by feeding in a single set of emissions trajectories under a single set of assumptions for key climate system parameters (e.g., climate sensitivity, ocean diffusivity and aerosol forcing), we automate a process to integrate MAGICC's executable and configuration files into a Java code script, in order to run a single set of trajectories under 100 different sets of parameter assumptions. In other words, I explore the uncertainty in climate system responses for a single emissions trajectory (from MESSAGE scenario output) by using a probability density function (PDF) to describe the following parameters: climate sensitivity, ocean diffusivity, and aerosol forcing. Therefore, instead of simply saying that, for a given mitigation scenario and emissions trajectory, "the projected maximum global temperature increase over the course of the twenty-first century is estimated at X ºC", I can say something like "the probability of staying below X ºC maximum global temperature increase is Y%."

The reason I estimate projections of climate system responses probabilistically is because of the large amount of uncertainty in key climate system parameters. Perhaps the most important among these, and one of the most uncertain, is climate sensitivity, which refers to the equilibrium global average warming expected if $CO_2$ concentrations were to be sustained at double their pre-industrial values. This value is estimated, by the IPCC

Fourth Assessment Report (AR4) “as likely to be in the range 2 to 4.5°C with a best estimate of about 3°C” (IPCC, 2007). Contributing to the IPCC AR4 were a number of studies that estimate PDFs for climate sensitivity (see Meinshausen et al. (2009), and O’Neill, Riahi, et al. (2010) for good reviews). And as Figure 85 illustrates, the shape of these PDFs can be quite different. In this study, our group divided each of these PDFs into 100 steps between 0.1 and 10 ºC. PDFs for ocean diffusivity and aerosol forcing, two other important though uncertain climate parameters, were then generated by correlating them with climate sensitivity at each step (Meinshausen, 2006). Although there is the potential to use any of the PDFs shown in Figure 85, I focus on the Forest et al. (2002) distribution with uniform priors (bold line in figure), since it is near the middle of the range found in the literature and also so that my results are directly comparable to those of previous studies on this topic (e.g., O’Neill, Riahi, et al. (2010)). Note that a climate sensitivity value of 3 ºC has a likelihood of 53.9% using the PDF from Forest et al. (2002).

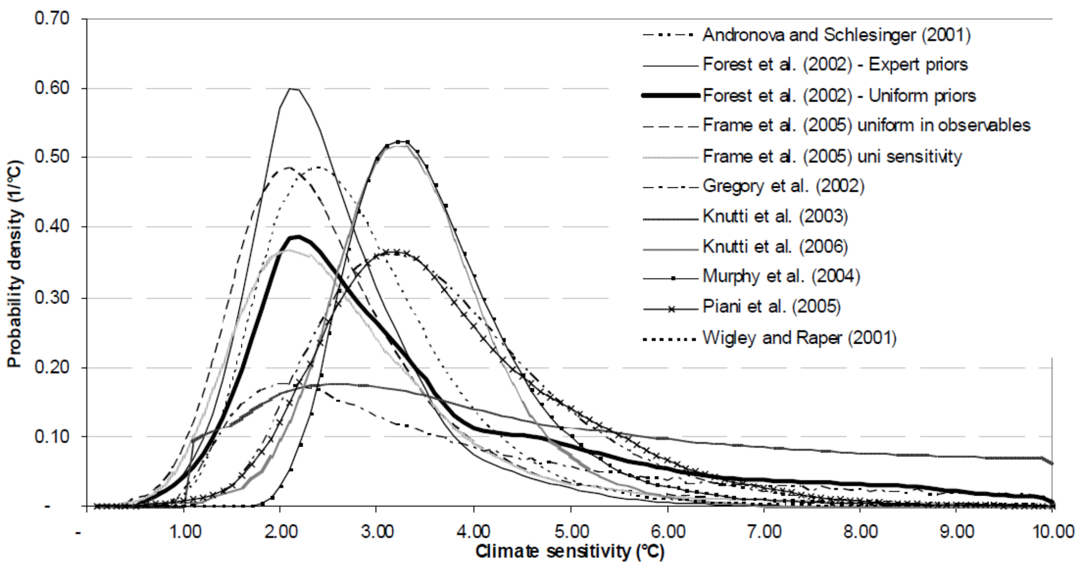


**Figure 85 Probability Density Functions (PDF) for Climate Sensitivity (figure from O'Neill et al. (2010); reproduced with permission)**

### *III.2.3 Joint Modeling Framework and Study Design*

A thorough analysis of synergies and trade-offs among energy objectives necessitates a broad scenario space, stretching the potential development of the energy system in several dimensions. Therefore, in this project several hundred scenarios were developed, each of which meets the different objectives (climate mitigation, air pollution and health, energy security, and affordability) in a unique way. For instance, some scenarios push the climate mitigation objective while ignoring security and air pollution reduction, at least explicitly, while other scenarios prioritize only security while ignoring the other objectives. By generating a large ensemble of potential energy system futures, a significant portion of the feasible scenario space is covered.[57]

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[57] Note that achievement of the access objective is taken as given in this analysis, as all scenarios have been developed to meet the access targets of the GEA, including even the baseline scenario. This simplification

Since this project has been conducted in support of the Global Energy Assessment, the scenario ensemble that is created here springs from one of the three core scenario pathways developed for the Assessment, specifically the GEA-Mix. For a brief description of these pathways, see Box 1; for a fuller description, including the underlying scenario assumptions, see GEA (2011).) In other words, assumptions for global population and gross domestic product (GDP) development and the availability of technologies are the same as in the standard GEA-Mix pathway. The problem is that no baseline scenarios are developed in the GEA, only the pathways that meet the targets for sustainability. Hence, it became necessary in this analysis to relax some of the constraints in the GEA-Mix pathway, in order to develop a baseline with business-as-usual energy system development. Then, from this baseline, within the MESSAGE modeling framework, several hundred scenarios were developed by imposing varying combinations of policy constraints at varying levels of stringency across several different dimensions. In particular, constraints are imposed on three important variables: cumulative global GHG emissions over the entire model time horizon (1990-2110); global annual GHG emissions in 2050; and absolute upper limits on the total amount of energy that can be supplied by imports in a given region and year, starting in 2030.[58] Note that because the full scenario ensemble covers a large portion of the feasible scenario space, the GEA-Mix is inherently included. Also, it is important to realize that the objective function is the same in all scenarios – total discounted energy system costs

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was made because energy access, compared to other objectives, has the lowest impacts on energy use and GHG emissions.

[58] For an extended discussion of how energy security policies are modeled in MESSAGE, see the appendix.

are minimized over the entire model time horizon. It is simply the constraints of the scenarios that differ, i.e., how far they push each energy objective.

**Box 1**
*Description of the Global Energy Assessment Scenario Pathways*

The GEA-Mix scenario pathway of the Global Energy Assessment is used in this project as a starting point for populating the scenario ensemble with a large number of potential energy futures. In brief, there is a single overarching storyline for the GEA, in which transformation of the energy system over the course of the twenty-first century occurs in such a way that all energy objectives are met simultaneously. The quantitative targets of the GEA scenario include: 1) universal access to electricity and modern cooking fuels in all regions of the world by 2030; 2) reduction of premature deaths due to air pollution 50% by 2030; 3) limitation of global average temperature increase to 2 ºC above pre-industrial levels with a likelihood of >50% in order to avoid dangerous climate change; and 4) improvement of energy security by 2050 by constricting global trade flows and increasing the diversity and resilience of energy supply. There are, of course, manifold pathways by which the normative objectives of the GEA could potentially be met in the future; however, for manageability the Assessment simply develops three core pathways (GEA-Supply, GEA-Efficiency, and GEA-Mix), along with several dozen pathway variants. Each of these pathways is designed to describe transformative changes toward a more sustainable future, and each is constructed to represent a different emphasis in terms of demand-side efficiency improvements and supply-side transformations. For example, the GEA-Supply pathway emphasizes supply-side changes but little on the demand-side efficiency; therefore, the growth projections for end-use demand across all sectors are relatively high. The GEA-Efficiency pathway, on the other hand, emphasizes demand-side measures (faster than the historical trend for improvement) and achieves relative low demand as a result. The GEA-Mix pathway represents an intermediate ground between the GEA-Supply and GEA-Efficiency pathways and, thus, leads to intermediate levels of demand growth in the future.

The three GEA pathways share a set of harmonized assumptions about future drivers of global change, namely population and gross domestic product within each world region, and their pace of socio-economic development is consistent with other studies in the literature. For instance, global population increases from almost 7 billion at present to roughly 9 billion by around 2050, before declining toward the end of the century. Such a trajectory represents a median development path based on demographic projections by the United Nations (2009). With respect to economic development, global GDP roughly triples by 2050 and increases more than seven times by 2100. Developing and emerging economies are projected to grow faster than currently industrialized countries, with the total economic output of the former surpassing that of the latter by about 2040. On average, global per capita income in the GEA scenario pathways grows at an annual rate of 2% over the next half-century. The following figures show the global population and GDP projections underlying GEA pathways, as well as for all of the scenarios in the full ensemble of the current study. (The full range of projections from the literature are shown by the shaded region, while the median projections used in this and the GEA studies are highlighted with a trend line. The inserts in the upper left corners show development for each of the industrialized and developing regions.)

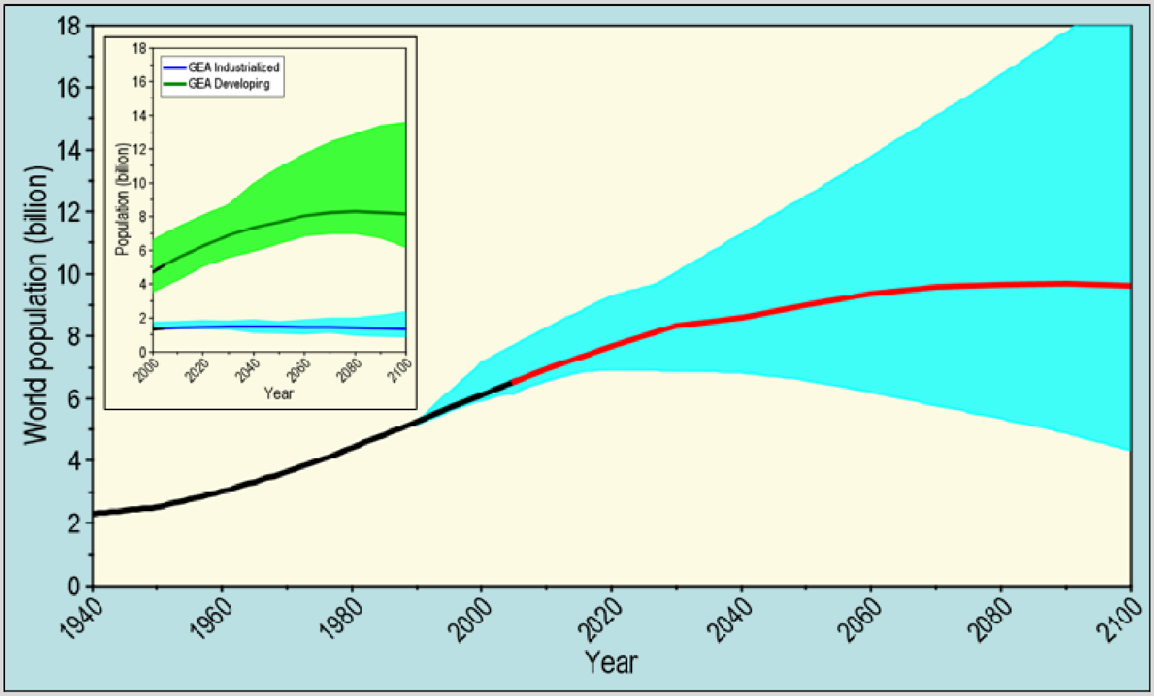


**Figure 86  Projections for Global Population in the Scenarios Used in the GEA and This Study**
**(Source:  Global Energy Assessment (GEA, 2011))**

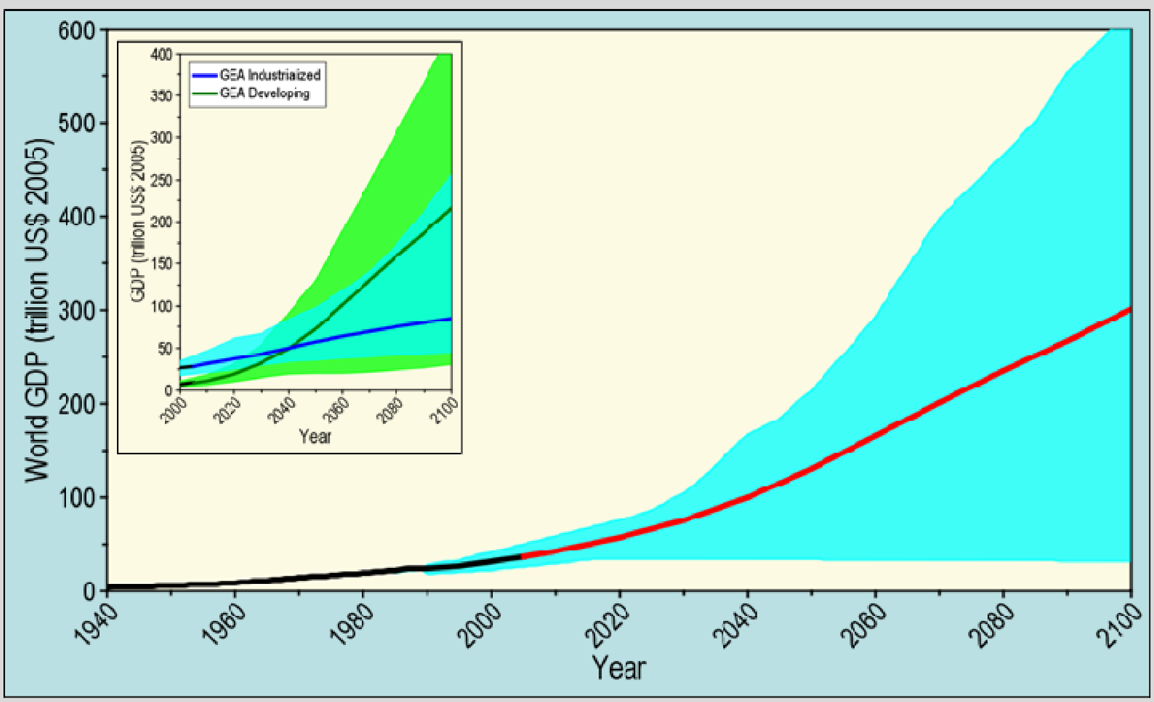


**Figure 87  Projections for Global Economic Development in the Scenarios Used in the GEA and This Study**
**(Source:  Global Energy Assessment (GEA, 2011))**

Furthermore, the GEA-Mix pathway assumes a full and diverse portfolio of supply-side technological options. In other words, advanced, yet uncertain, technologies – such as nuclear, CCS, renewables, and biomass – are available in all of the GEA pathways and, by extension, all of the scenarios developed for the current study. Of particular note, global biomass potential tops out at about 200 EJ by 2050 and remains at this level until 2100 (GEA, 2011).

To estimate air pollutant emissions and pollution control costs for each MESSAGE energy scenario, data and output from IIASA's Greenhouse Gas and Air Pollution Interactions and Synergies (GAINS) model was utilized (Amann et al., 2009).[59] At each of the different levels of pollution control stringency and for each pollutant and region, emissions factors by were obtained from GAINS for each corresponding energy technology in MESSAGE. In addition, for a given level of pollution control stringency, GAINS was used to estimate the cost of installing all necessary pollution control equipment by energy technology (i.e., higher stringency requires more expensive control technologies). Care was taken not to double-count MESSAGE and GAINS technology costs.

Finally, after using MESSAGE to generate a large ensemble of scenarios, the emissions trajectories of each are fed to the MAGICC global climate model. As discussed previously, MAGICC is used to estimate climate system impacts, for example, projections for atmospheric GHG concentrations, radiative forcing, global annual-mean surface air temperature, and sea level rise. In particular, my research focuses on the probability of staying below 2 ºC maximum temperature increase over the century.

[59] I gratefully acknowledge Shilpa Rao, Peter Kolp, and Wolfgang Schöpp for their invaluable roles in translating the pollutant emissions factor and cost estimates from GAINS to MESSAGE.

The two-step process described here culminates in several hundred unique energy and emissions scenarios, which in practice takes several days of computer time to complete.

## III.3 Characterization of the Full Scenario Space

Figure 88 illustrates the full scenario space in the climate dimension. Each scenario of the large ensemble has a unique GHG emissions trajectory. In the baseline scenario, for instance, annual emissions grow from 13,450 Mton Carbon-eq in 2010 to 22,841 Mton C-eq in 2050, a level that is 121% greater than emissions in 1990 (10,322 Mton).[60,61] Emissions then peak near 26,000 Mton in the later part of the century. All other scenarios achieve emissions reductions compared to the baseline. In the most stringent climate scenarios, for instance, emissions in 2050 are just 5,161 Mton, 50% below 1990. Depending on the particular emissions trajectory, each scenario is associated with a unique probability for reaching the 2 ºC target – the probability of staying below 2 ºC maximum temperature rise, relative to pre-industrial levels, throughout the twenty-first century. (The uniform prior climate sensitivity PDF from Forest et al. (2002) is used to do the probabilistic assessment in this case.) These probabilities are shown in Figure 88 for various ranges of scenarios. Note that reaching the 2 ºC target with greater than 50% probability requires that emissions peak in 2020 at levels that are only marginally higher than today and then be reduced significantly in the decades that follow.

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[60] The GHG estimates include all well-mixed Kyoto greenhouse gases ($CO_2$, $CH_4$, $N_2O$, $SF_6$, $CF_4$, and halocarbons).

[61] To convert between carbon (C) and carbon dioxide ($CO_2$), multiply the carbon by 44/12 (the ratio of the molecular weight of carbon dioxide to carbon). For comparison, annual $CO_2$-only emissions in 1990 and 2010 are estimated at 7,516 and 9,657 Mton C, respectively. In the baseline scenario, $CO_2$ emissions are projected to climb to 17,287 Mton C in 2050.

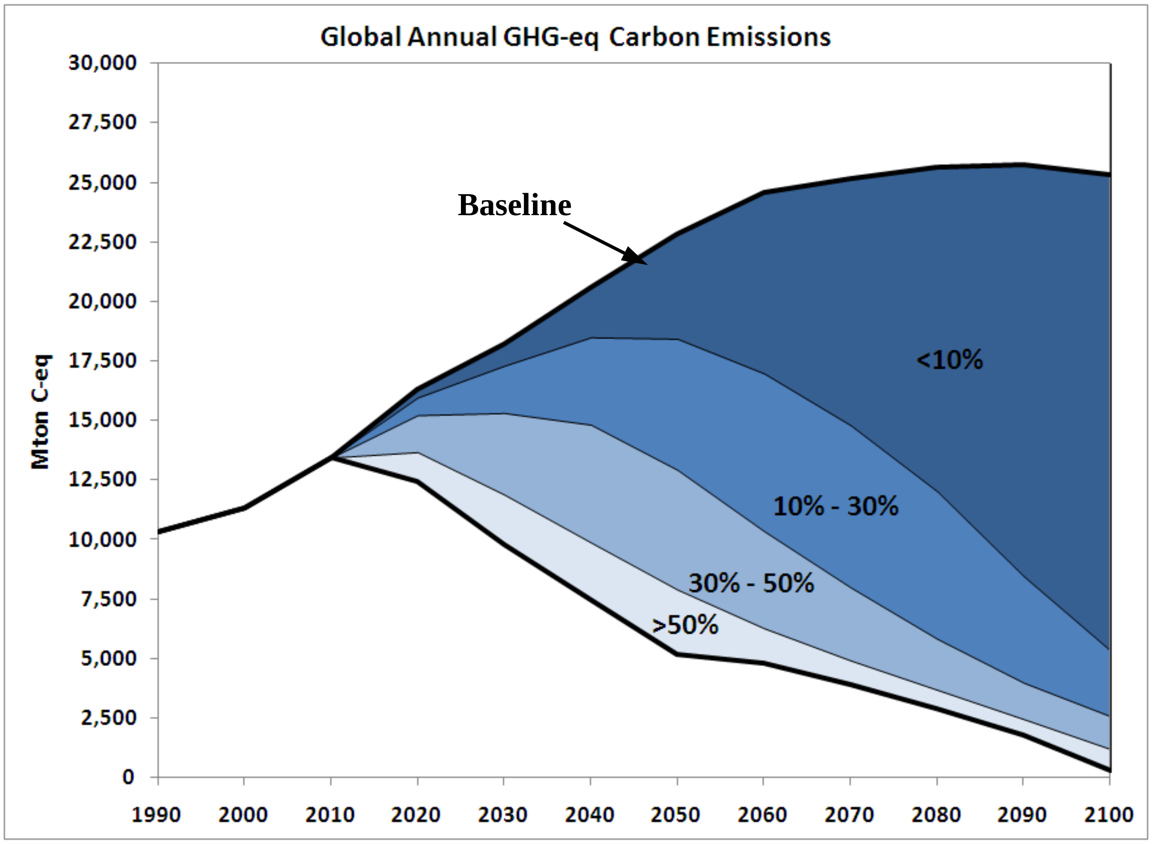


**Figure 88 Global Greenhouse Gas Emissions Trajectories for the Full Scenario Ensemble**

Air pollutant emissions depend on the structure and composition of the energy system and on the nature of the pollution control strategies employed. Hence, the pollutant emissions trajectories of each of the scenarios in the ensemble are determined by the stringency of policy in three key areas: pollution control, climate mitigation, and energy security. As with GHG emissions, each scenario of the large ensemble possesses unique emissions trajectories for sulfur dioxide ($SO_2$), nitrogen oxides ($NO_x$), volatile organic compounds (VOC), carbon monoxide (CO), black carbon (BC), organic carbon (OC), ammonia ($NH_3$), and fine particulate matter (PM 2.5). Typical pollution control strategies to limit the generation of these chemical species include utilization of low-sulfur fossil fuels (especially for coal and petroleum-based fuels) and application of “end-of-pipe" technologies, such as flue gas desulfurization, selective catalytic reduction, electrostatic precipitators, and particulate filters, for both stationary and mobile sources. In addition, pollution can be reduced through measures that are typically thought of as climate mitigation strategies: energy efficiency improvements, combined heat and power (CHP), fuel switching (e.g., from coal and oil to natural gas), and utilization of nuclear and renewable energy technologies.

For the purposes of this analysis, four different levels of air pollution legislations are considered. (For further details on the types of controls assumed in each case, see Knowledge Module 17 of the full Global Energy Assessment report (GEA, 2011).) These include:

- **FLE**
  Frozen Legislation; no change in future pollution policies relative to 2010 in all regions
- **CLE**
  Current and planned Legislation for air quality is enacted in all regions (baseline case)
- **SLE**
  Stringent Legislation for air quality that exceeds CLE levels; feasible, aggressive pollution control is enacted in all regions; implementation level is 70% of what could theoretically be achieved via MFR in every region
- **MFR**
  Maximum Feasible Reduction; best practice technologies of today are employed in every region by 2030; theoretical limit to pollution control

Figure 89 attempts to illustrate the full space of the scenario ensemble in the air pollution dimension by showing, as an example, the ranges of PM 2.5 emissions trajectories. Particulate matter is chosen as a representative pollutant for this discussion because, of all types of air pollutant emissions, PM 2.5 causes some of the most serious impacts on human health; thus, it can be used as a proxy for health impacts, as has been done in a number of recent analyses (e.g., Amann (2009)). One observes that a CLE policy in the absence of policies on climate change, as is the case in the baseline, leads to a low reduction in PM 2.5 emissions of less than 5% in 2030 compared to today, whereas application of SLE and MFR levels of pollution control leads to a sharp reduction of air pollutants for the same energy scenario (i.e., the same technologies and fuels being used in the energy system, only with more stringent pollution control). Alternately, by driving the energy system toward zero-carbon, emissions-free technologies, stringent climate and security policies can also play a role in reducing pollutant emissions, even under a relatively slack air pollution policy regime (FLE or CLE). This is shown by the wide-ranging extent of the FLE and CLE regions in the figure. The lower borders of these regions show how far PM 2.5 emissions can be reduced with stringent climate and security policies. Reducing pollution via climate mitigation comes at a cost, however, as discussed later in this section. In the most extreme scenario – stringent climate and security policies combined with either SLE or MFR pollution control – global PM 2.5 emissions in 2030 fall to roughly half of the 2010 level.

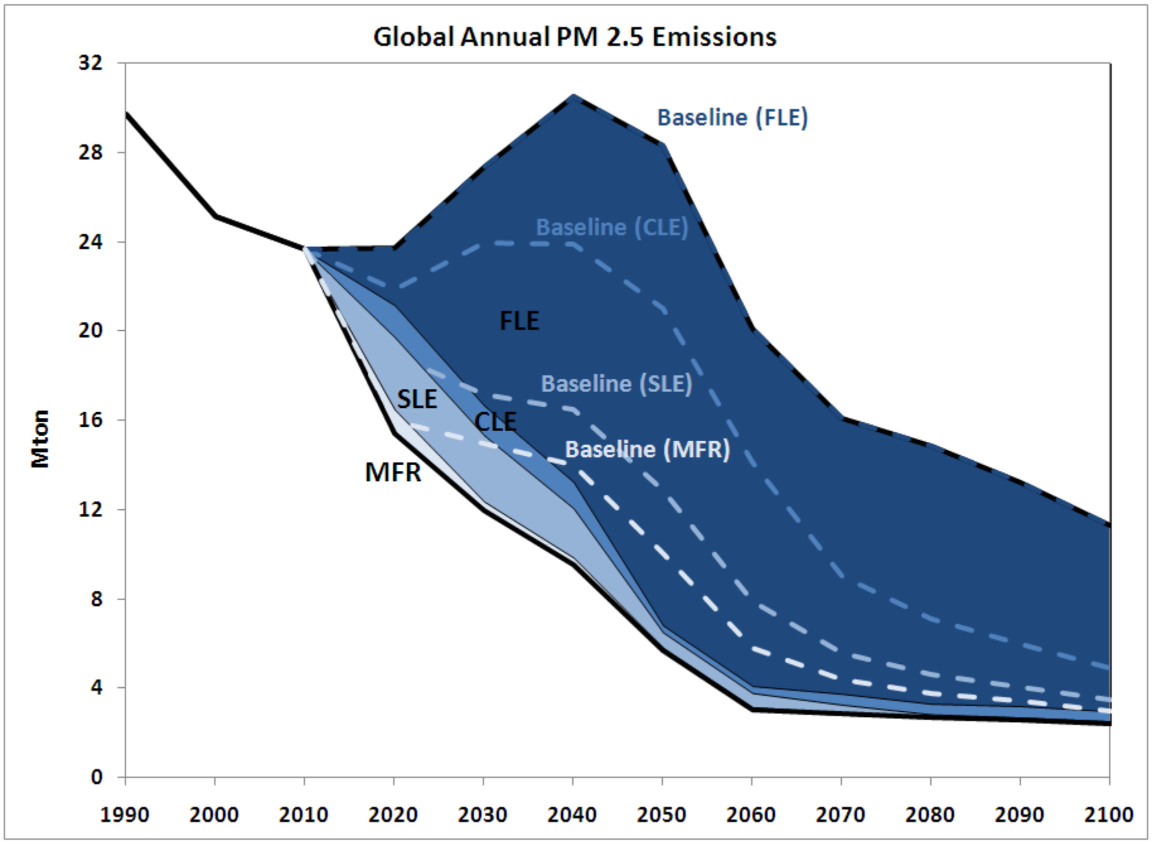


**Figure 89 Global PM 2.5 Emissions Trajectories for the Full Scenario Ensemble**

The scenarios also cover a broad space in the energy security dimension, although, as yet, there is no real consensus as to the precise definition of security (Kruyt et al., 2009). Therefore, as discussed above, this analysis models security in a straightforward, transparent way: limiting energy trade flows between individual regions in order to reduce import dependence. The underlying premise is that in a future world where security becomes a major concern, countries might shift towards trade partners that are fairly similar in the geographic, political, economic, and cultural sense. Such a paradigm would represent a marked shift from the situation as it exists today, but that being said, energy security has not exactly been high on the priority list of most countries until fairly recently. Furthermore, past examples show that increased domestic production and reduced imports do not always guarantee a reliable, secure energy supply. (Consider, for example, the coal miners' strike in the Great Britain in 1984.) Nevertheless, in spite of these caveats, I have chosen to operationalize energy security in terms of import constraints in this study. In future work alternate formulations will be applied. For reference, note that as of 2010, only five of the eleven MESSAGE regions – Western Europe, Central and Eastern Europe, Pacific OECD, Other Pacific Asia, and South Asia – imported more than 35% of their total primary energy supply from all sources, while North America's net import share stood at 24% and that of Centrally Planned Asia and China was 3%. The other regions (Sub-Saharan Africa, Middle East and North Africa, the newly independent states of the Former Soviet Union, and Latin America and the Caribbean) are actually net *exporters* at the present time (i.e., they have a negative net import share) and are projected to continue in this capacity for many decades to come. It is perhaps noteworthy that even while North America's share of imported energy is not dramatically high, relative to some other regions of the world, even this level has become a major concern for policymakers in recent years, particularly because a high percentage of crude oil consumed in the U.S. is sourced from foreign markets (>50%).

Other strategies to achieve energy security include diversification of energy supply (with respect to resources and/or trading partners) and attempts to dampen volatile price swings. In this analysis, the diversity of the energy mix within each region is estimated with two simple diversity indicators, one that only takes into account the diversity of primary energy resources ($I_1$) and another that also takes into account where those resources are sourced, whether from imports or domestic production ($I_2$). Both of these indicators derive from the Shannon index (Jansen et al., 2004; Kim et al., 2009; Kruyt et al., 2009; Stirling, 1994). Both diversity indicators increase with increasing diversity of the energy system, but the second indicator decreases at higher levels of import dependency. In either case, the higher the diversity indicator for a given country or region, the more secure is its energy system.

$$I_{1,i} = -\Sigma_j \, (p_j \bullet \ln p_j) \quad (1)$$

$$I_{2,i} = -\Sigma_j \, \{ \, (1 - m_j) \bullet (p_j \bullet \ln p_j) \, \} \quad (2)$$

where:

- $I_1$: energy diversity indicator #1 in region $i$ (resources only)
- $I_2$: energy diversity indicator #2 in region $i$ (resources + imports)
- $p_j$: share of primary energy resource $j$ in total primary energy supply
- $m_j$: share of primary energy resource $j$ that is supplied by (net) imports

Figure 90 illustrates the range of diversities achieved in the scenarios, using the region with the lowest diversity indicator ($I_2$) in 2030 – i.e., the worst performing region – as a proxy for overall global performance across the energy security dimension. Each bar in the figure represents a single scenario, and the scenarios are sorted in order of decreasing diversity (i.e., lower energy security). For reference, the red box highlights the range of diversity indicators of the world's seven importing regions at present (North America, Western Europe, Central and Eastern Europe, Pacific OECD, Other Pacific Asia, South Asia, and Centrally Planned Asia and China). Note that the baseline scenario is one of the least desirable scenarios in terms of diversity: virtually every other scenario, whether through climate or security policy, achieves a greater diversification of the energy mix by 2030.

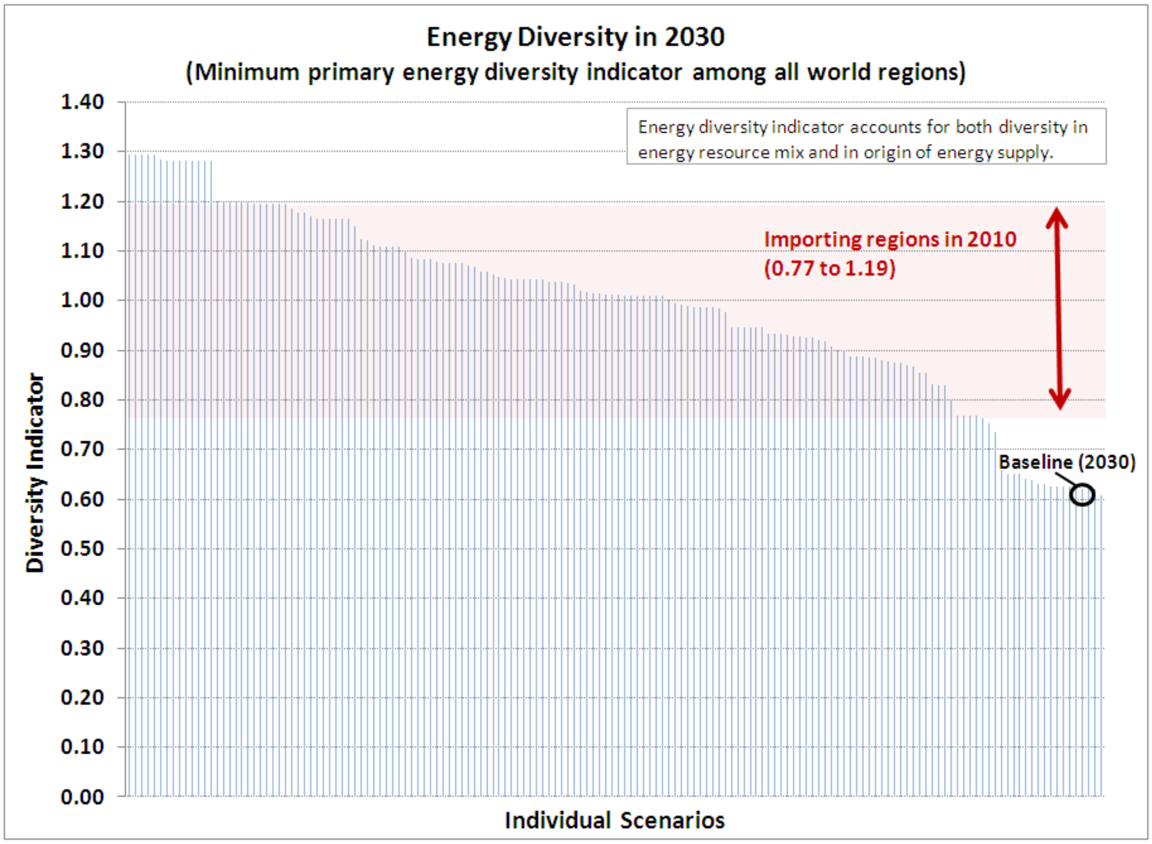


**Figure 90 Energy Diversity in 2030 for All Scenarios in the Full Ensemble [minimum primary energy diversity indicator among all world regions is used as a proxy for global performance]**

Because the individual scenarios in the ensemble vary so greatly along the dimensions of climate mitigation, energy security, and pollution control, total energy system costs span a fairly wide range. This is illustrated in Figure 91, where each bar represents a single scenario, and the scenarios are sorted in order of increasing costs, which include the cumulative discounted sum between 2010 and 2050 of energy system investments (for both climate mitigation and energy security), pollution control investments, O&M, fuel, non-energy mitigation, and demand reduction (i.e., energy efficiency improvements and conservation).[62] Total costs for each scenario are then related to the cumulative

[62] A discount rate of 5% is used.

discounted sum of global gross domestic product (GDP) over the same time period and subsequently normalized to the costs incurred in the baseline scenario.[63]

This "policy cost" measure attempts to capture the added costs of energy, climate, and pollution control policies relative to the baseline scenario. As shown in the figure, achieving the 2 ºC target with greater than 50% probability does not appear to be possible in any of the scenarios where global policy costs are less than 1.0% of GDP. On the other hand, achievement of the target is quite likely in virtually all scenarios where policy costs are greater than 1.25% of GDP. In between these two levels is an intermediate region, where some scenarios meet the target and others do not. The variability in this intermediate region can be attributed to the particular combination of objectives being pushed in each scenario. For instance, scenarios with stringent climate policies but relatively weaker security and pollution control policies may be able meet the 2 ºC target with >50% probability at a lower cost (say, between 1.0% and 1.25%) than a scenario with the same climate policies but, in addition, much more stringent security and pollution control policies (costs >1.25%).

An important caveat to this analysis is that it only does a partial economic accounting. It attempts to capture the multiple benefits of climate mitigation, energy security, and pollution control in terms of total energy system *costs*. However, the analysis largely ignores the significant economic *benefits* of pursuing these three objectives. For instance, it does not consider the avoided costs (i.e., benefits) of climate change (e.g., more

[63] Total global energy system costs (not policy costs) are projected to be roughly 2.2% of global GDP between 2010 and 2050.

frequent extreme weather events, impacts on global agriculture and food production) or of climate adaptation (e.g., construction of sea walls, relocation of coastal populations). Similarly, the benefits accruing from reduced health expenditures and increased life expectancies have not been monetized here. Given this partial accounting, it is highly likely that the cost figures shown in this section are somewhat overestimated. This is a known issue with integrated assessment models used to inform energy and climate policymaking (Nemet et al., 2010).

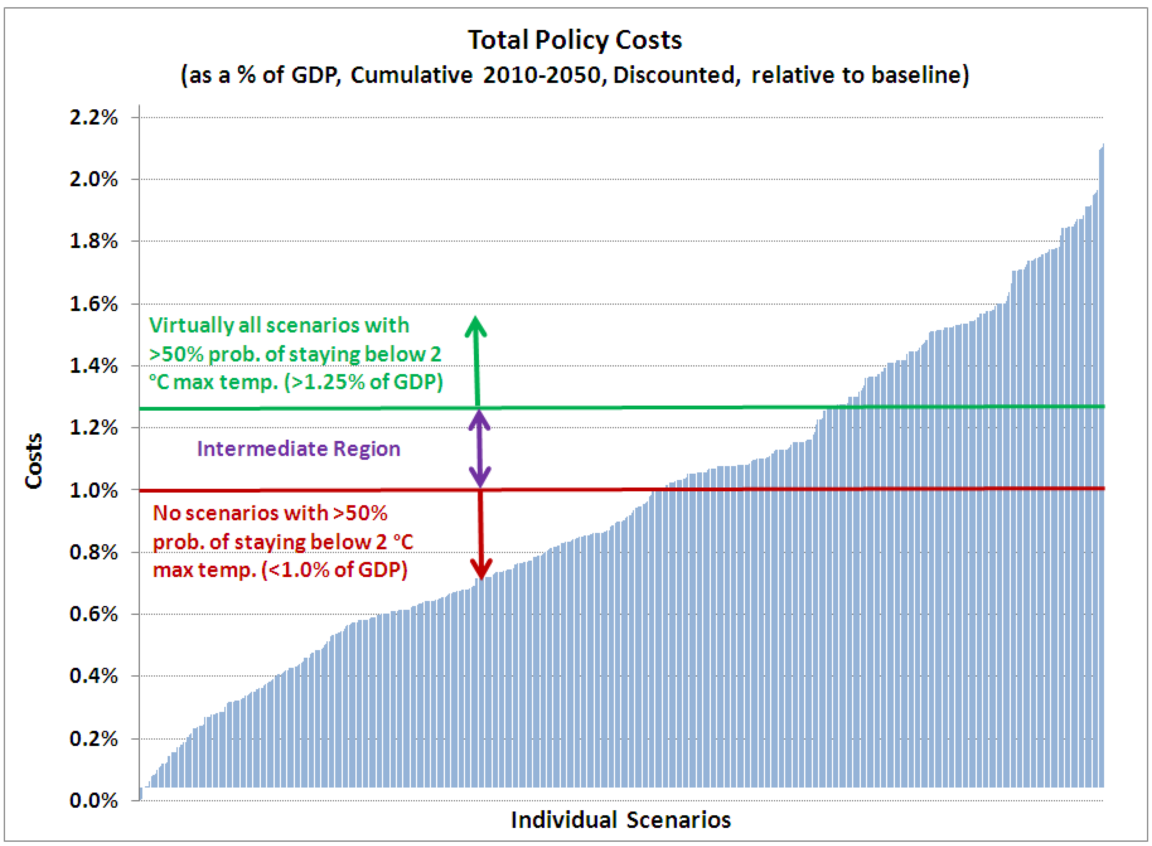


**Figure 91 Total Policy Costs for All Scenarios in the Full Ensemble [cumulative from 2010 to 2050, discounted, as a % share of GDP, relative to baseline]**

## III.4 Synergies and Trade-offs Between Objectives

As the discussions above have already begun to show, the inherent synergies, and to a lesser extent the trade-offs, between the various objectives can be illuminated through analysis of a large ensemble of possible energy futures. Among energy planners and decision makers, however, these relationships are not well enough understood. Cost trade-offs are obviously the most familiar: the greater society's aspiration for a sustainable energy future, the larger the costs. But as for questions like: *How much extra might it cost to achieve each additional objective? How can costs be reduced by pursuing multiple objectives?* These issues are much less clear. This section highlights the main findings of one of the few attempts in the scenario literature to explore the important relationships between climate mitigation, energy security, and reduced air pollution (for further reading, see van Vuuren et al. (2006), Cofala et al. (2009), Cofala et al. (2010) and Bollen et al. (2010)).

### *III.4.1 Near- and Mid-Term Actions to Achieve Long-Term Objectives*

Probabilistic assessment of the relationship between greenhouse gas emissions and global temperature change has been studied by den Elzen and van Vuuren (2007), Schneider and Mastrandrea (2005), Keppo et al. (2007), Meinshausen et al. (2009), and O'Neill, Riahi, and Keppo (2010). The current analysis builds on these previous studies and extends them through inclusion of additional energy objectives. Figure 92 shows, for the wide-ranging ensemble of scenarios described above, maximum global mean surface air temperatures relative to pre-industrial levels over the 21$^{st}$ century (at the IPCC 4AR best estimate climate sensitivity value of 3 ºC) as a function of the cumulative quantity of greenhouse gas emissions (considering all Kyoto gases) emitted between 2000 and 2049 (i.e., the GHG emissions budget). Stringency of air pollution legislation is shown in the third dimension, using data markers of differing colors and shapes. Two noteworthy trends emerge from the figure.

First, as climate policy becomes more stringent and GHG emissions are increasingly limited, maximum transient temperatures are considerably reduced, from greater than 4 ºC in the baseline scenario to less than 2 ºC in the most stringent climate scenarios. Note that, although not shown, in all scenarios global temperatures peak in the second half of the century, following the peak in net global radiative forcing by at least a couple of decades, due to time lags in the global climate system (Clarke et al., 2009).

Second, temperatures appear to increase with the stringency of pollution control, at least according to the definition of pollution control in this study, which assumes that all pollutants (PM 2.5, $SO_2$, $NO_x$, VOCs, CO, BC, OC, and $NH_3$) are simultaneously limited in equal proportions. This pollution control impact on the climate becomes stronger at higher levels of GHG emissions (in the figure, note how the separation between the pollution cases widens at higher emission levels), increasing temperatures by a small, but non-trivial, 0.2 to 0.4 ºC in the most extreme case (i.e., the baseline scenario). This phenomenon can be explained by the greater shares of fossil energy technologies that comprise the energy system in the high-GHG scenarios. Fossil technologies are directly impacted by pollution control, whereas zero-carbon energy technologies, which make up an increasing share of the system in the low-GHG scenarios, do not generate air pollutant emissions and, thus, do not require pollution control. In other words, because the process of decarbonization reduces pollution so strongly in the scenarios with more stringent climate policy, the added impact of end-of-pipe pollution control measures on the climate is far smaller.

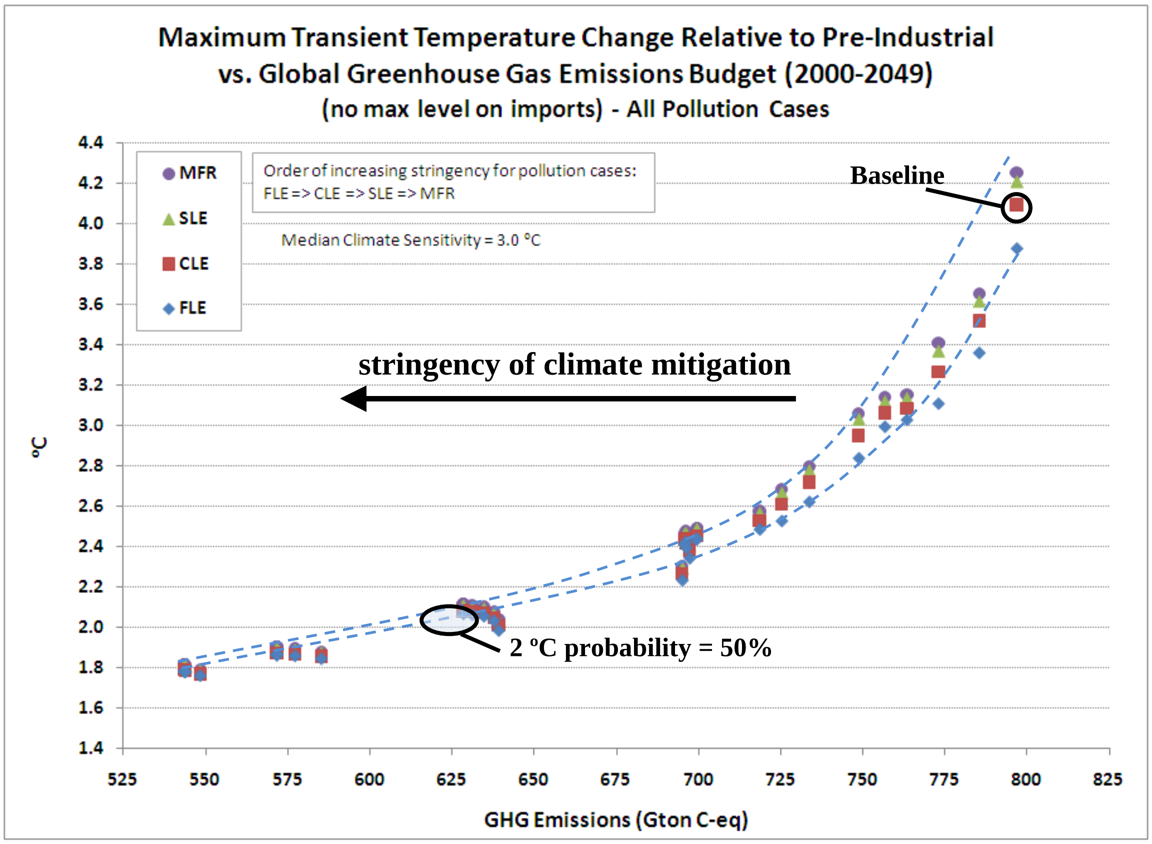


**Figure 92 Relationship Between the GHG Emissions Budget from 2000 to 2049 and Maximum Global Mean Surface Air Temperatures Relative to Pre-Industrial Levels**

Herein lies the main trade-off between pollution control and climate mitigation, a topic that is addressed more fully in Section III.4.2 and Box 2, the latter of which highlights the climate feedbacks of reducing air pollutant emissions, particularly climate-cooling aerosols. In sum, for an equivalent amount of radiative forcing from fossil components (e.g., $CO_2$, $CH_4$, etc.), an “across-the-board” reduction in air pollution tends to increase warming, on balance. Such an outcome need not be the case, however, as there are a number of different ways that pollution could be controlled, in theory. While a wholesale reduction in pollution may be the best approach for minimizing human health impacts and also for certain environmental reasons (e.g., acid rain), it may not be the best strategy for the climate. In fact, one could imagine scenarios in which specific pollutants are proportionally reduced more than others, for example, warming components, such as black carbon and the ozone precursors ($CH_4$, $NO_x$, CO, and VOCs), are reduced more than cooling components, such as $SO_2$ and organic carbon, in an effort to preserve the overall cooling effect of aerosols and, thus, to produce a net gain for the climate, or at least to remain radiant energy-neutral (Cofala et al., 2009; Ramanathan and Xu, 2010).

Related to the current discussion, Figure 93 shows the relationship between the probability of staying below 2 ºC maximum temperature rise (relative to pre-industrial levels) throughout the century and the GHG emissions budget between 2000 and 2049. Consistent with Clarke et al. (2009), the 2 ºC probability is found to vary considerably depending on the stringency of the GHG emissions budget. In particular, meeting the 2 ºC target with greater than 50% probability requires limiting the GHG emissions budget (considering all Kyoto gases) to less than 625 Gton C-eq (2,292 Gton $CO_2$-eq) over the first half of the century. To put this number in perspective, cumulative global GHG emissions between 2000 and 2010 were approximately 119 Gton C-eq (~19% of the total budget). Hence, assuming that the global GHG emissions rate could be held constant at the current level of 13.45 Gton C-eq (49.3 Gton $CO_2$-eq) per year for the next several decades, the total GHG emissions budget would be “spent” before 2040. In actuality, however, given that global GHGs are projected to increase rapidly in a Baseline scenario, the emissions budget could be spent by around 2030. Moreover, with regard to the impact of air pollution on the global climate, stringent pollution control appears to reduce the probability of staying below the 2 ºC temperature target by up to four percentage points, depending on the scenario.

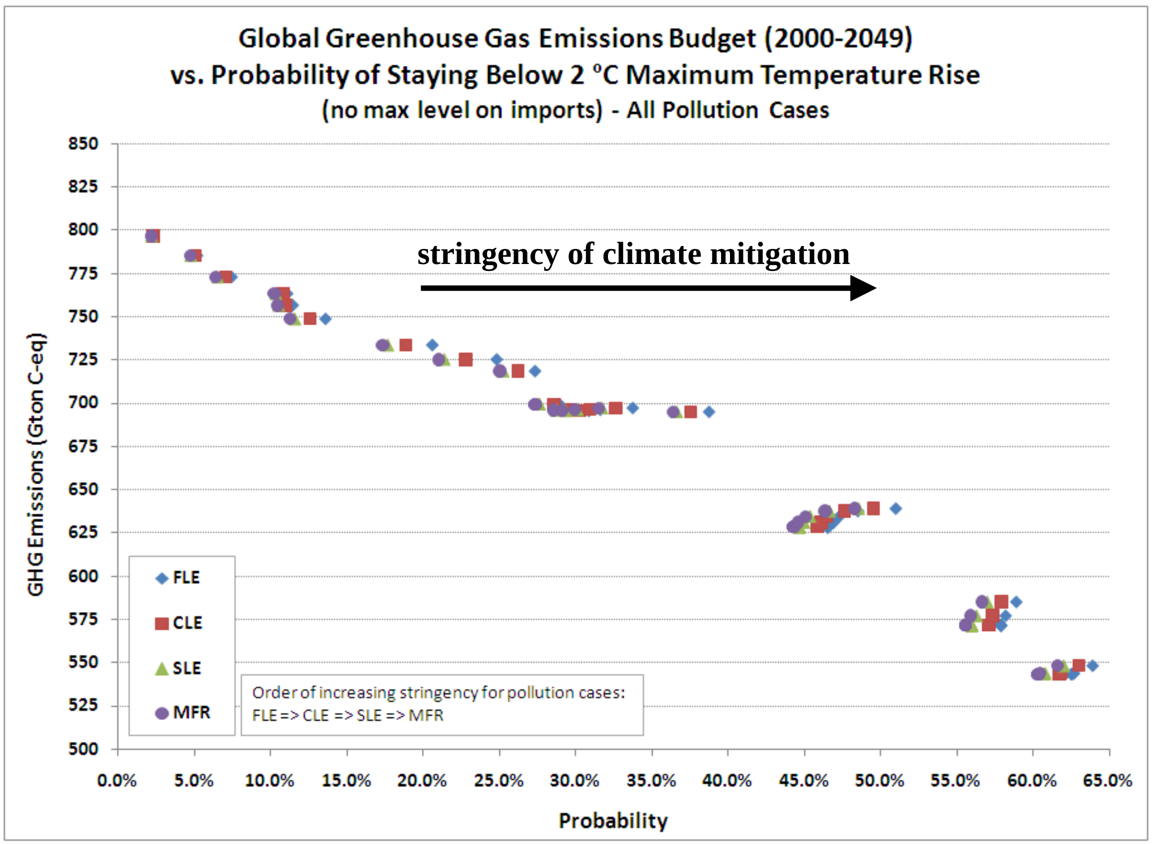


**Figure 93  Relationship Between the GHG Emissions Budget from 2000 to 2049 and Probability of Staying Below 2 ºC Maximum Temperature Rise Relative to Pre-Industrial Levels**

These 2 ºC probability results discussed here are compatible with, though slightly more optimistic than, those of Meinshausen et al. (2009), who are notable for having conducted pioneering work in this area. For example, Meinshausen et al. (2009) estimate that with a GHG emissions budget of 625 Gton C-eq, the probability of staying below the 2 ºC target ranges from 14% to 53%, depending on the particular climate sensitivity PDF that is chosen.[64] Using the uniform prior climate sensitivity PDF from Forest et al. (2002), as is done in the current analysis, a probability of 38% is estimated by Meinshausen et al. (2009). Put another way, based on the calculations of Meinshausen et al. (2009), meeting the 2 ºC target with 50% probability (using the Forest et al. (2002) uniform prior PDF; full range of 34% to 75% using other PDFs) would require limiting the GHG emissions budget to 567 Gton C-eq over the first half of the century, a bit less than the 625 Gton C-eq level calculated in this analysis. The reasons for these discrepancies are two-fold. First, a different version of the climate model MAGICC is used in this analysis. Second, in the current analysis a number of stringent climate policy scenarios in the large ensemble achieve near-zero or even negative GHG emissions in the latter part of the century. In contrast, very few scenarios with this kind of trajectory were considered in the analysis of Meinshausen et al. (2009). Thus, for a given likelihood of staying below the 2 ºC target, their calculations would naturally suggest that greater GHG reductions must be achieved in the first part of the century, thereby lowering the required emissions budget. Moreover, similar to Meinshausen et al. (2009), this study finds that the relationship between the 2000-2049 GHG emissions budget and the 2 ºC probability is strongly correlated; and on top of that, it appears to be quite linear. In fact, for every 41.7 Gton C-eq reduction in the emissions budget – approximately 3.1 years' worth at current global emission rates – the 2 ºC probability increases by ten percentage points.

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[64] These probability estimates are calculated using the "The PRIMAP 2°C Check Tool", which summarizes the full data set underlying Table 1, Figure 3 and Figure S1 of Meinshausen et al. (2009) (found at http://sites.google.com/a/primap.org/www/nature). Note that in actuality, Meinshausen et al. (2009) calculate the probability of *exceeding* the 2 ºC target, rather than staying below it, and they quote their GHG emissions estimates in units of either $CO_2$-only or $CO_2$-eq (all Kyoto gases considered) rather than C-eq.

**Box 2**
*Net Global Radiative Forcing*

According to the IPCC Fourth Assessment Report (4AR), "Radiative forcing is a measure of how the energy balance of the Earth-atmosphere system is influenced when factors that affect climate are altered" (Solomon et al., 2007). This equilibrium, which refers to the balance between incoming solar radiation and outgoing infrared radiation within the Earth's atmosphere, controls the surface temperature of the Earth. The term "forcing" refers to the notion that the factors affecting the climate are pushing the Earth's radiative balance away from its normal state (generally construed to be the pre-industrial era (pre-1750), before human activities led to the extensive alteration of natural land cover and generation of significant quantities of greenhouse gas and air pollutant emissions). Therefore, radiative forcing can be thought of as a relative measure, comparing the forcing that is experienced today, or at some point in the future, versus the forcing that prevailed during pre-industrial times. Radiative forcing is typically estimated as the "rate of energy change per unit area of the globe as measured at the top of the atmosphere". It is normally expressed in units of "Watts per square meter" ($W/m^2$).

A number of chemical and physical components contribute to net global radiative forcing (Figure 94). Some of these have long atmospheric lifetimes (e.g., $CO_2$, $CH_4$, $N_2O$, and various halocarbons including HCFCs, HFCs, PFCs, and $SF_6$), while others decompose or are converted rather quickly in the atmosphere (e.g., air pollutant emissions and/or the chemical species they act as precursors for: ozone, CO, $NO_x$, VOCs, $SO_2$, BC, and OC). The radiative forcings of some of these individual components operate on a continental or global scale (e.g., GHGs and pollutant emissions), whereas others are more regional in nature (land use changes and black carbon on snow and ice). Perhaps most importantly, some components contribute to warming (positive forcings), while others cool the Earth (negative forcings). As illustrated in Figure 94, the long-lived greenhouse gases are responsible for the bulk of global warming, and their contribution is the dominant radiative forcing term. This category also has the highest level of scientific understanding. In contrast, the contributions from the cooling components (total aerosols and cloud and surface albedo effects) are less well understood and have larger uncertainties. Note that the contribution from aerosols, while likely negative in total, is actually comprised of both positive forcing components (e.g., BC) and negative forcing components (e.g., $SO_2$, OC, and nitrate and mineral dust aerosols).

On balance, net global radiative forcing (between 1750 and 2005) is positive, with a best estimate of +1.6 $W/m^2$ [90% confidence interval: +0.6 to +2.4 $W/m^2$] (Solomon et al., 2007).

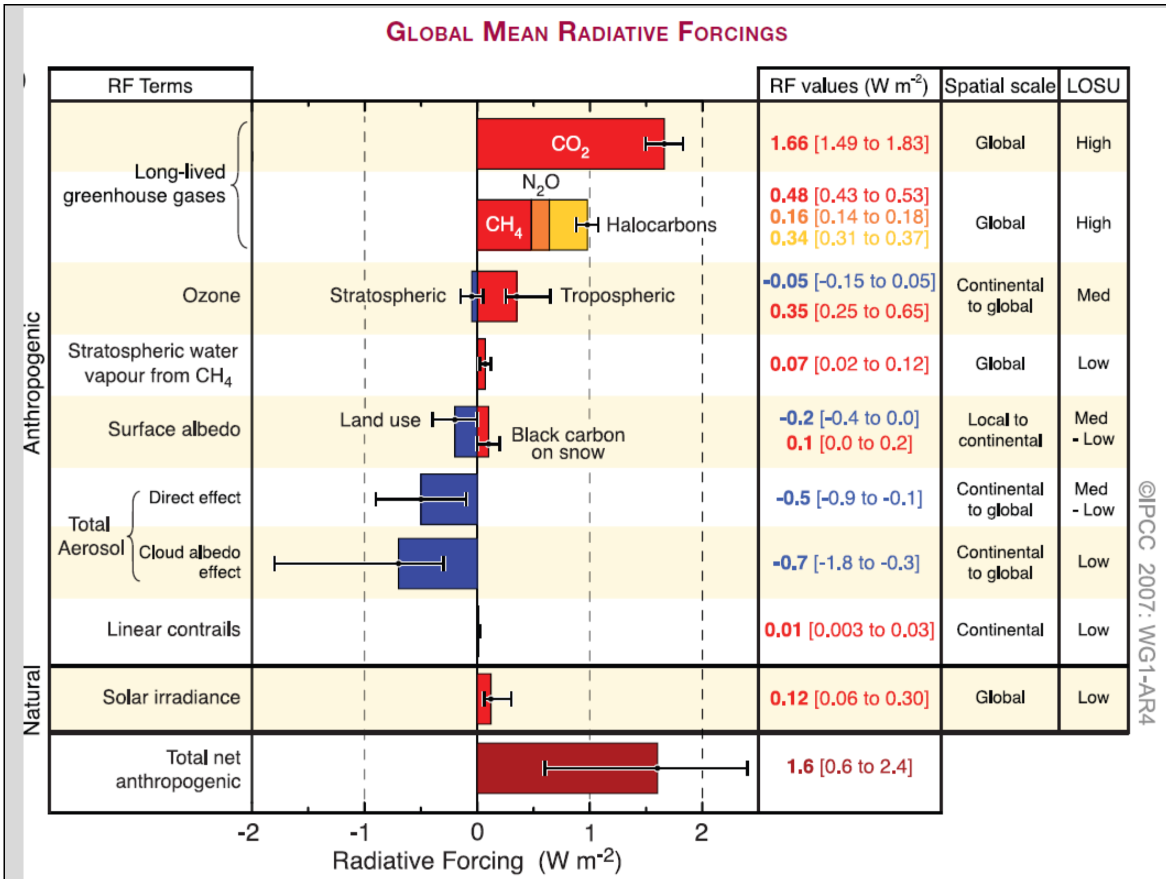


**Figure 94 Global Mean Radiative Forcings (RF) in 2005**
**[90% confidence intervals shown in brackets; LOSU = level of scientific understanding] (Source: Solomon et al. (2007))**

Limiting global temperature rise and increasing the probability of staying below the 2 ºC temperature target necessitates decarbonization of the global energy system. This will be achieved largely through increased utilization of zero-carbon technologies (renewables and nuclear)[65] and the application of carbon capture and storage (CCS) to fossil and biomass conversion technologies. Hence, a useful near-term measure for attaining society's longer-term climate objectives is the share of total primary energy derived from

[65] In this section, "zero-carbon energy" is defined as energy derived from nuclear and renewables (biomass, hydro, wind, solar, and geothermal). This definition does not include CCS.

zero-carbon sources in 2030.[66] As Figure 95 illustrates, the likelihood of staying below the 2 ºC warming target throughout the century increases dramatically as zero-carbon energy utilization increases beyond the fairly low shares (~10%) that would otherwise be realized in 2030 under a baseline scenario. Specifically, achieving the 2 ºC target with greater than 50% probability in the long term requires zero-carbon energy shares in the near term (2030) approaching 20-25% or higher. Yet, while it is not immediately obvious from the figure, this actually equates to a less than 2.5x increase in total zero-carbon energy supply (in EJ), due to the double dividend effect of climate policy: zero-carbon energy sources become more attractive under stringent climate policy and at the same time total energy demand/supply from all sources is reduced (because of efficiency and conservation). Thus, shares of zero-carbon energy supply grow faster than in absolute terms.

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[66] Primary energy for nuclear, hydro, wind, solar and geothermal is calculated using *direct energy equivalents*.

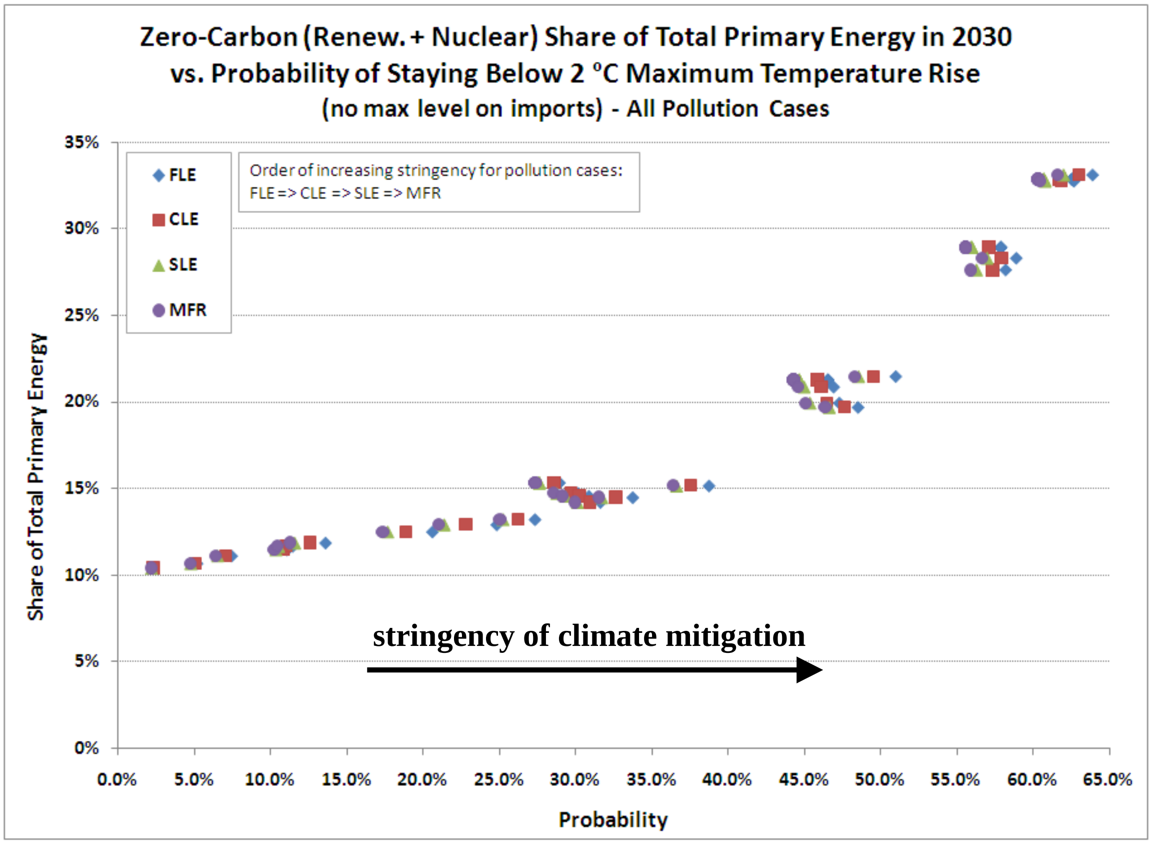


**Figure 95 Relationship Between Shares of Zero-Carbon Energy (Nuclear and Renewables) in 2030 and the Likelihood of Staying Below the 2 °C Warming Target**

### *III.4.2 Climate Mitigation and Air Pollution*

In addition to limiting climate change to "safer" levels, decarbonization of the economy has the supplementary benefit of reducing pollution and its impact on human health (Amann, 2009; Nemet et al., 2010; Swart et al., 2004). Put more directly, climate mitigation is an important entry point for achieving society's pollution-, and by extension health-, related goals. This is shown clearly in Figure 96, which relates global PM 2.5 emissions in the near term (2030) to the probability of staying below 2 °C maximum temperature rise over the course of the century. As the energy system is decarbonized and increasing shares of zero-carbon, pollution-free technologies are utilized, the 2 °C probability increases, and pollutant emissions are significantly reduced. In fact, the levels of pollutions in the most stringent climate scenarios with CLE pollution control (~16 Mton) are similar to those with much lower climate stringency but much more stringent pollution control policies (SLE and MFR). In other words, near-term targets for pollution reduction can be achieved just as effectively through climate policy as they can through stricter pollution control measures that are enacted in the absence of climate policy. Another interesting trend in Figure 96 is that the spread between the four pollution control cases narrows as the system is decarbonized, showing that the impacts of pollution control policy are much less variable as zero-carbon technologies penetrate the market and fossil technologies are forced out. This occurs because pollution control is applicable to fewer technologies (e.g., power plants, factories, vehicles, etc.) when there is less fossil energy in the system.

Figure 97 shows similar relationships for the regions of Centrally Planned Asia and China (CPA) and South Asia (SAS), the latter of which largely consists of India. Taken together, these two regions are projected to account for more than half of all global PM 2.5 emissions in 2030 in the baseline scenario. Therefore, decarbonization of the energy system and/or pollution control are particularly critical in these parts of the world because of the dramatic improvements in human health that can be realized (see KM-17 of the full GEA report for a further discussion of health impacts).

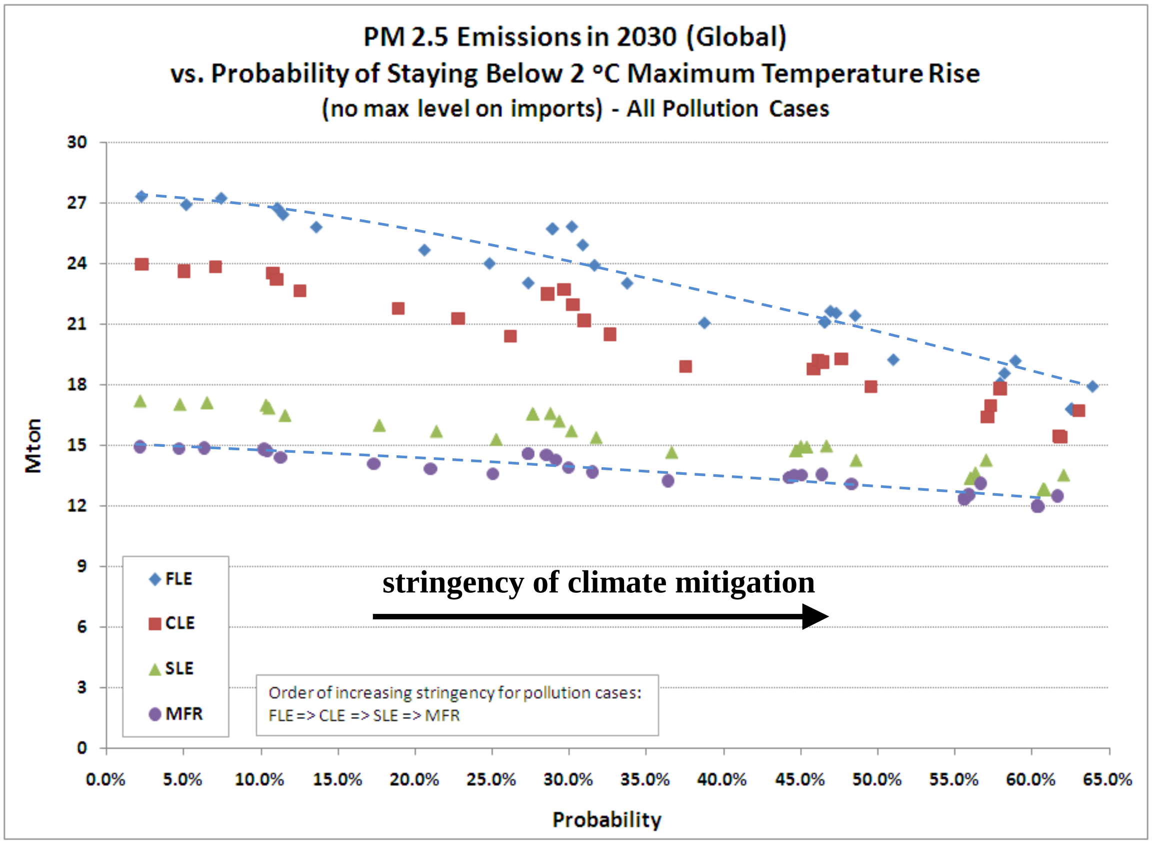


**Figure 96 Synergies Between Near-Term PM 2.5 Emissions and Climate Mitigation (Global)**

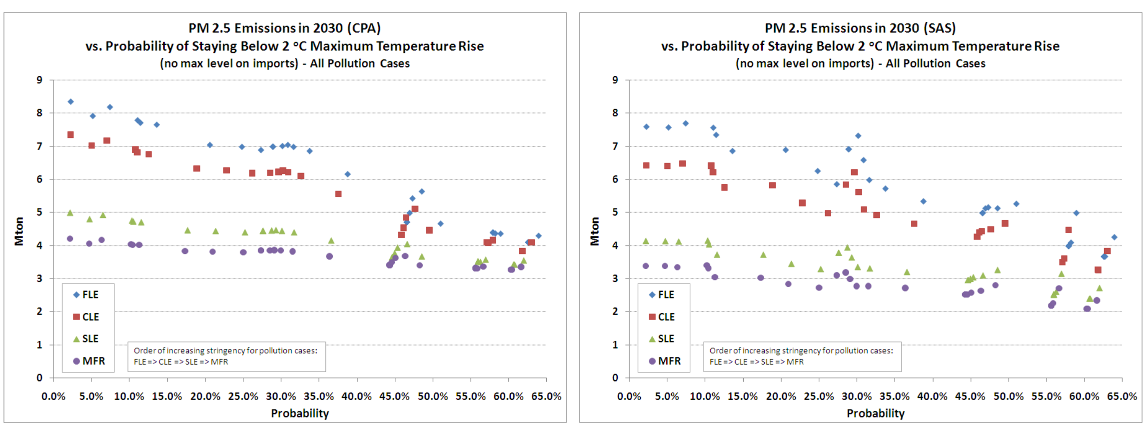


**Figure 97 Synergies Between Near-Term PM 2.5 Emissions and Climate Mitigation (CPA and SAS Regions)**

Reducing global air pollution levels – whether through air pollution legislation or climate policy, or both – will necessarily lead to additional energy system costs, an important trade-off that relates to policy choices and the resulting direction of the energy system. However, given the enormous co-benefits between pollution and climate policy, achieving society's pollution/health objectives via climate mitigation as an entry point has the potential to significantly reduce the added costs of pollution control, as illustrated in Figure 98 which plots pollution control costs (relative to all other energy system costs) for each scenario in the ensemble.

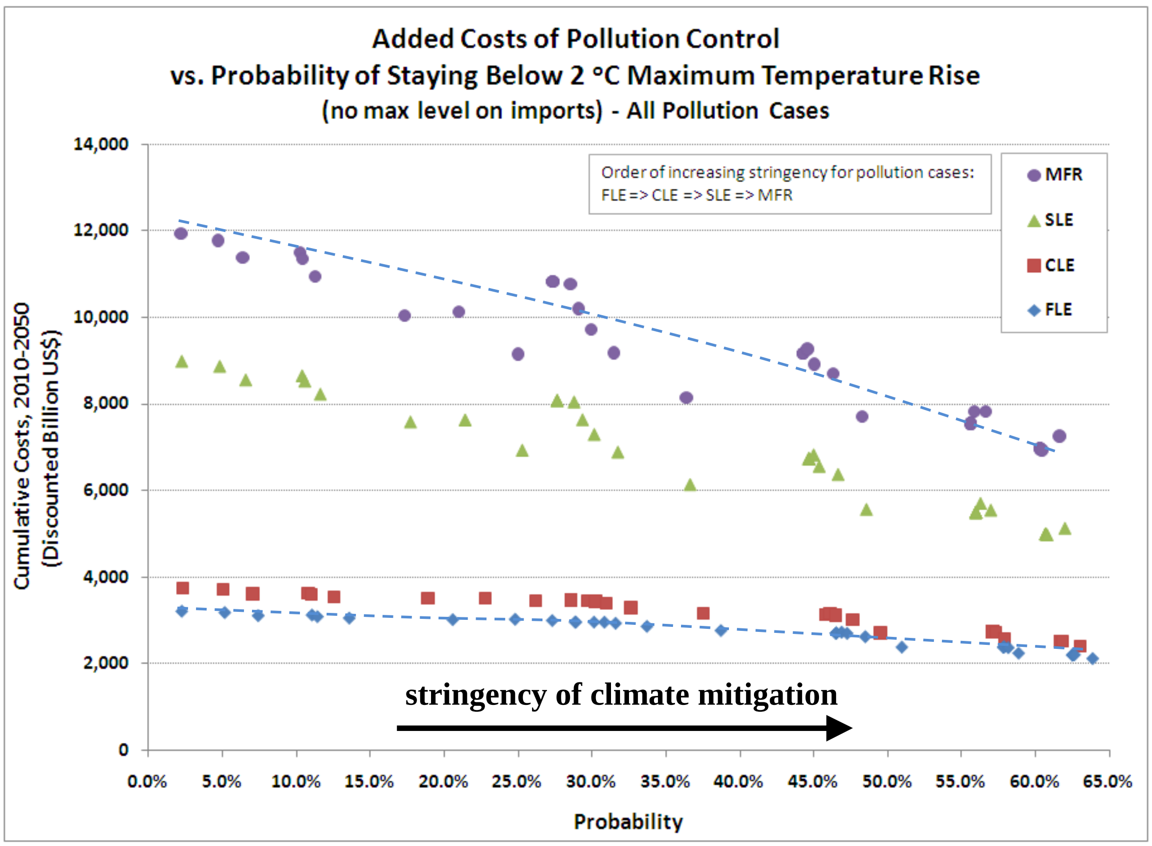


**Figure 98 Synergies Between Pollution Control Costs and Climate Mitigation**

A closer look at three select scenarios of the ensemble provides a more detailed understanding of the climate-pollution-cost relationship. These three scenarios are shown in Figure 99: (1) the baseline scenario with SLE pollution control; (2) a scenario with intermediate climate stringency and CLE pollution control; and (3) the most stringent climate scenario with CLE pollution control. Compared to the baseline scenario with pollution control policies at the CLE level (Current and planned Legislation is Enacted), in which global PM 2.5 emissions in 2030 are projected at 23.9 Mton, each of these focus scenarios achieves a significant, and roughly similar, level of reduction. Declines of this magnitude, as well as proportionally similar reductions for other pollutant emissions ($SO_2$, $NO_x$, VOCs, CO, BC, OC, and $NH_3$), add a significant $773 billion to total annual energy system costs in the Baseline (SLE) scenario in 2030, compared to $1,759 billion for all other energy system costs (investments and O&M). In contrast, while the structural changes that come along with mitigating the climate also add significantly to total energy system costs[67], these costs can be partially offset by pollution control benefits. This is a striking result of the current analysis, and it corroborates findings from other studies (e.g., Amann (2009) for Europe): namely that a significant portion of climate mitigation costs can be compensated for by reduced pollution control costs. As Figure 99 illustrates, in the Intermediate Climate (CLE) and Stringent Climate (CLE) scenarios, the additional annual costs of pollution control in 2030 are just $195 and $133 billion, respectively – some $578 and $640 billion less (-75% and -83%) than the pollution control costs needed in Baseline (SLE) to achieve a similar level of pollutant emissions reduction.

Moreover, the co-benefits of climate mitigation and air quality also show up as avoided human health impacts. By the author's calculations, based on marginal damage costs

[67] It is important to note that because the climate costs shown here include investments in low-carbon technologies along with their corresponding variable costs, demand reduction (energy efficiency investments and conservation efforts) beyond the baseline, and non-energy GHG mitigation measures, they may appear larger than estimates reported elsewhere for climate mitigation, especially with respect to the Stringent Climate (CLE) scenario.

from other studies (specifically Nemet et al. (2010)), these air quality co-benefits average $8 to $752 billion per year (mean: $188 billion) over the 2010 to 2030 time period in the Intermediate Climate (CLE) scenario and $14 to $1,390 billion annually (mean: $345 billion) in the Stringent Climate (CLE) scenario.[68]

Also noteworthy in Figure 99 are the sectors contributing to the added costs of pollution control. In the Baseline (SLE) scenario, all sectors require significant amounts of investment, with refineries and the residential and commercial end-use sectors being responsible for the bulk of investment. In the two climate scenarios, however, even with pollution control policies that are less aggressive *per se*, pollution costs decrease dramatically in virtually all sectors.

[68] The air quality co-benefits of reduced human health impacts are calculated by first estimating the cumulative GHG emissions reductions of the two climate scenarios compared to Baseline (CLE) between 2010 and 2030 and then multiplying by the marginal co-benefit of GHG reduction, as estimated in the literature and summarized by Nemet et al. (2010): $2 to $196 per ton $CO_2$, with a mean of $49/ton. (For the full distribution of values, see the original Nemet et al. (2010) paper.) These cumulative, undiscounted costs are then divided by 20 to estimate the annual average for each scenario over the 20-year timeframe. Note that the Baseline (SLE) scenario would also lead to reduced human health impacts due to air pollution reduction compared to Baseline (CLE). However, these are not calculated here because the marginal co-benefits estimates are presented in terms of $CO_2$ reductions, not air pollutant emissions reductions.

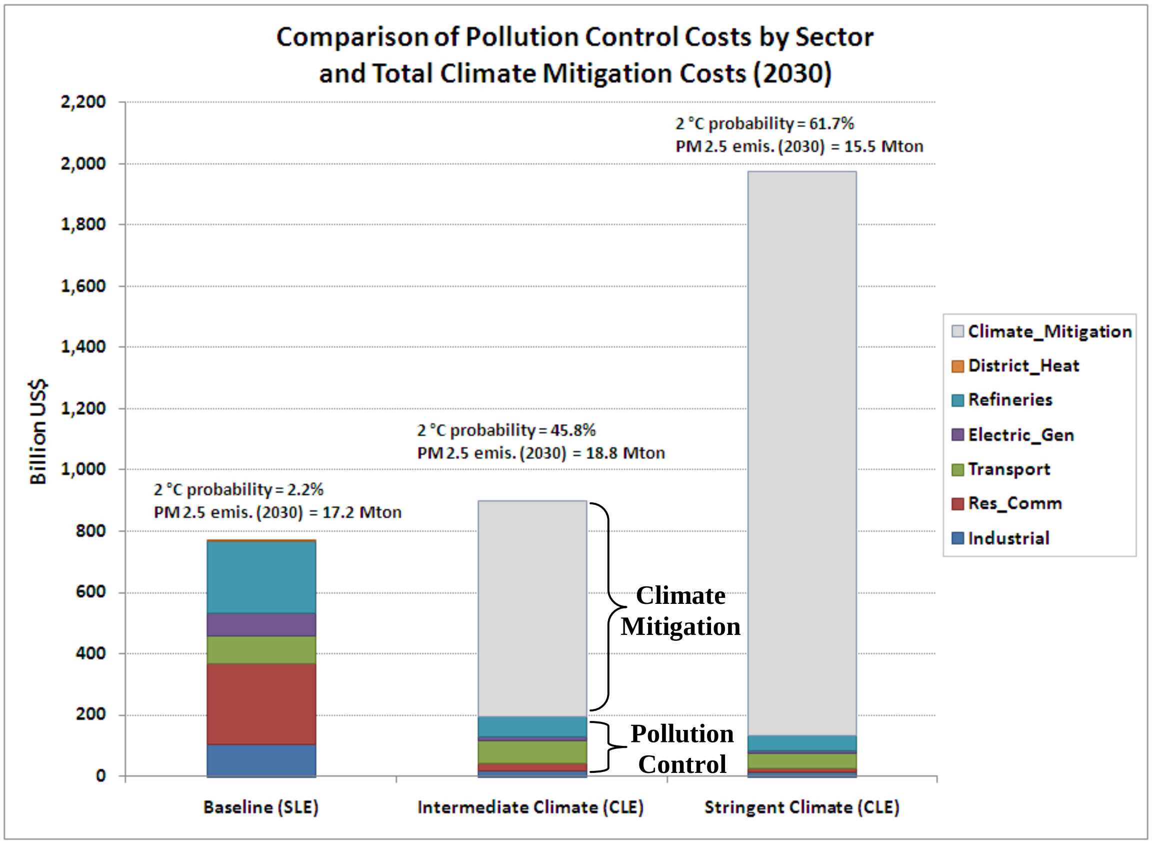


**Figure 99 Comparison of Pollution Control and Total Climate Mitigation Costs for Three Different Scenarios in 2030**

In sum, from an holistic and integrated perspective the combined costs of climate mitigation and pollution control come at a significantly reduced total energy bill if the benefits of pollution reduction are properly figured into the calculation of greenhouse gas abatement strategies (see also Nemet et al., (2010) for a similar conclusion). The design of cost-effective future policies, therefore, needs to integrate holistic portfolios of measures, which address both pollution and climate objectives simultaneously. This is, of course, no simple task, given that in many countries air pollution and climate change are dealt with by separate policy institutions. Hence, the enormous co-benefits of the two objectives are often overlooked and the costs of reaching each objective individually are often overstated (Amann, 2009). Furthermore, from a technological perspective, a robust finding of this analysis is that a key strategy for meeting both climate and pollution/health objectives is through the increased utilization of zero-carbon, pollution-free energy technologies, such as nuclear and renewables.

### *III.4.3 Climate Mitigation and Energy Security*

The previous discussion has shown that near-term deployment of zero-carbon technologies can help to achieve both near-term pollution and health objectives and long-term climate targets. In addition, this study finds that there are important synergies between decarbonization and energy security, yet another key near-term objective, and that climate mitigation appears to be an important entry point for achieving energy security goals. In short, as countries and regions invest more heavily in renewables, in an effort to decarbonize their economies, they will by extension reduce their imports of globally traded commodities, such as coal, oil, and natural gas. Since renewables (biomass, hydro, wind, solar, and geothermal) have the potential to be produced almost entirely domestically (or at least regionally within a cluster of like-minded countries), they are inherently secure resources (intermittency and reliability are different issues). Moreover, increased utilization of renewables and nuclear energy tends to diversify the energy resource mix away from one that relies heavily on fossil energy. Hence, decarbonization has the potential to simultaneously reduce import dependence and increase energy diversity, both of which are important indicators of a more secure energy supply, as discussed in Section III.3. In this respect, the results of this analysis indicate that the most “secure” scenario, from the perspective of both diversity and trade, is one in which all regions pursue very stringent policies that promote both climate mitigation *and* reduced import dependence.

Figure 100 illustrates this relationship by showing energy diversity in 2030 as a function of the probability of staying below the 2 ºC warming target, with maximum import levels shown in the third dimension. The minimum primary energy diversity indicator ($I_2$, as introduced in the previous section) among all world regions (i.e., the worst performing, least diverse region) is used as a proxy for overall global performance along the security dimension. Figure 101 focuses on costs, showing the 2 ºC probability versus cumulative total global policy costs as a share of global GDP between 2010 and 2050, with maximum import levels shown in the third dimension. Note that only a subset of the scenarios from the full ensemble is shown, namely those corresponding to the CLE pollution control case.[69] Total policy costs, which are calculated relative to the baseline scenario, attempt to capture the added costs of all energy, climate, and pollution control policies.[70]

[69] The other pollution control cases (FLE, SLE, and MFR) show qualitatively similar trends.
[70] Costs include energy system investments, pollution control investments, O&M, fuel, non-energy mitigation, and demand reduction (i.e., the macro-economic response).

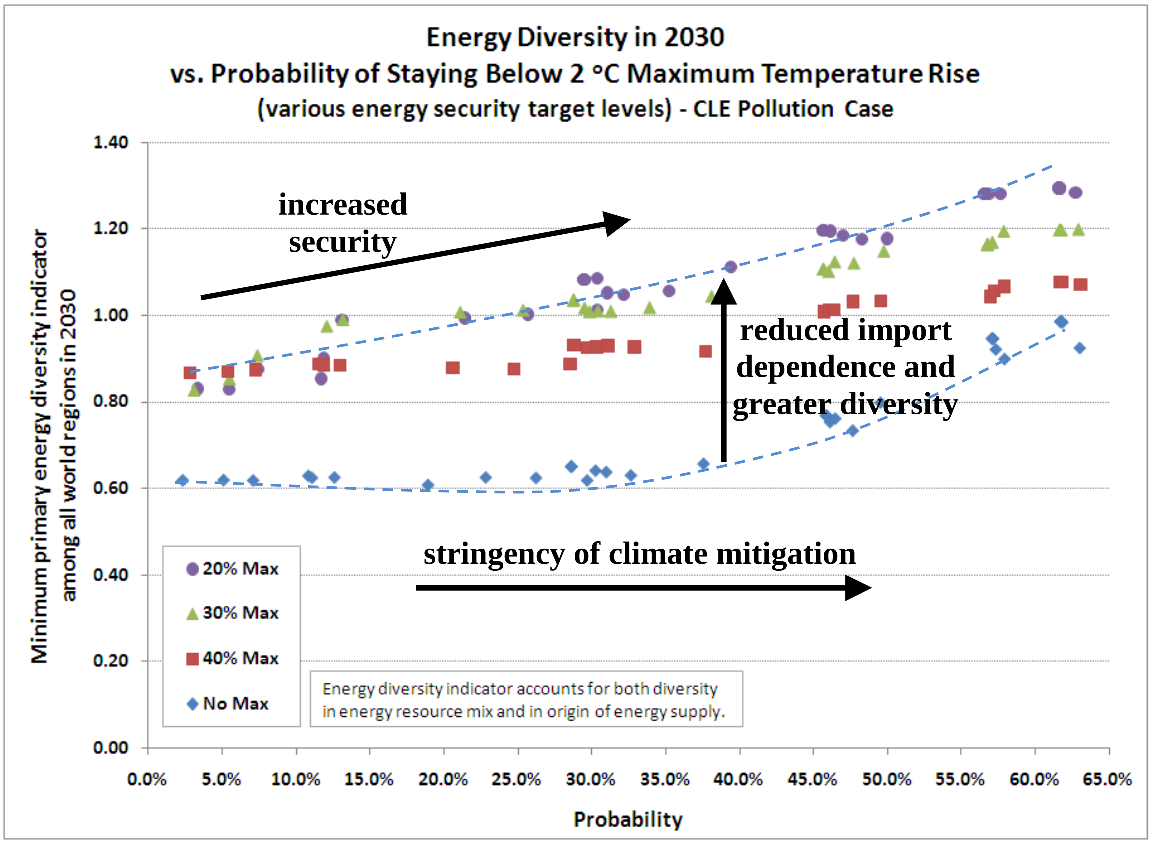


**Figure 100 Synergies Between Near-Term Energy Security Objectives and Climate Mitigation**

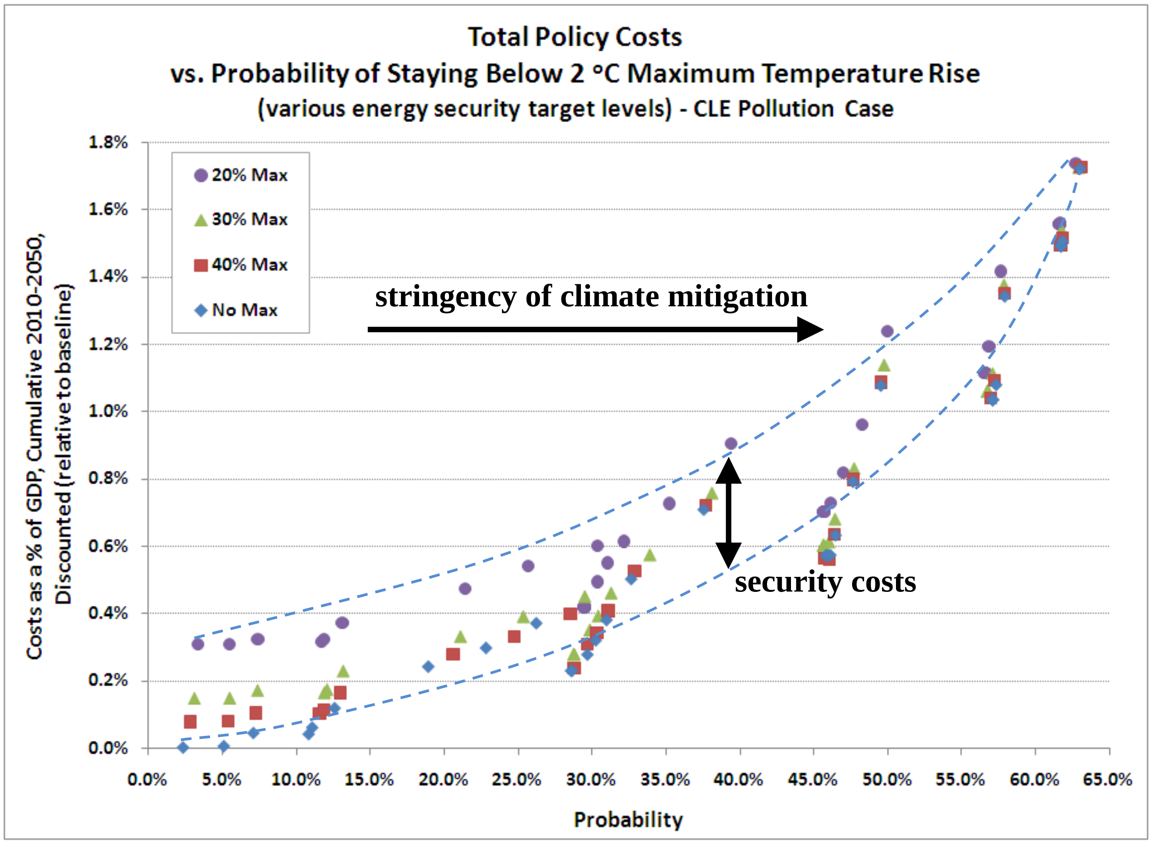


**Figure 101  Total Policy Costs for Simultaneously Achieving Energy Security and Climate Mitigation Objectives (Global)**

The double effects of decarbonization and reduced import dependence are quite clear from the figures.  As regions pursue strategies to mitigate the climate and/or enact policies and procurement strategies that prioritize domestic energy supplies over imports, the diversities of their energy resource mixes tend to increase.  Moreover, like pollution control, the pursuance of climate mitigation and energy security adds to total energy system costs.  The costs of security, however, are significantly reduced at higher levels of decarbonization, highlighting the multiple benefits of the two objectives.  This second point is illustrated by Figure 101.  At lower levels of decarbonization (i.e., correspondingly low 2 ºC probabilities), security costs can increase total system costs by as much as 0.3 percentage points. In contrast, under stringent climate policies, in which total global policy costs are roughly 1.7% of GDP, the added costs of security become extremely small, approaching zero.

Figure 102 provides a deeper look into the climate-security-cost relationship. Three different scenarios of the full ensemble are selected: (1) the baseline scenario; (2) a scenario with intermediate climate stringency; and (3) the most stringent climate scenario. Each scenario assumes CLE pollution control. For the Baseline scenario, if import dependence in each importing region could be reduced to less than 20% of its baseline total primary energy supply in 2030 (compared to a baseline where free trade dominates and there are no restrictions on trade flows) and then imports were capped at this level for the remainder of the century, globally aggregated energy system investments would increase by $240 billion annually in 2030. Such measures would primarily spur additional investments in efficiency, biomass production, synthetic fuels conversion, and non-fossil electricity generation, while at the same time reducing investments in fossil electricity generation and fossil energy extraction (namely coal mining and oil production). Yet, Figure 102 also shows, as is the case with air pollution control, when viewed from an holistic and integrated perspective, the combined costs of climate mitigation and energy security come at a significantly reduced total energy bill if the security benefits are properly figured into the calculation of greenhouse gas abatement strategies. For instance, in contrast to the Baseline scenario, where security costs are rather large, the added investment costs related to energy security in 2030 in the two climate scenarios decline to just $68 and $56 billion, respectively – reductions of 72% and 77% from the Baseline. These security benefits can largely be attributed to the reduced need for extra “security investments”, since climate policy promotes energy efficiency and conservation and the increased utilization of domestically produced, low-carbon energy sources. Of course, climate policy itself also adds to the total energy bill, so for comparison Figure 102 also shows climate mitigation costs in 2030 for the two climate scenarios. Climate costs are obviously quite substantial, though it is important to note that the cost accounting for climate policy is more comprehensive than that shown for security. Climate mitigation considers all costs beyond those motivated by security policy, including investments in low-carbon technologies and the associated variable costs, demand reduction (energy efficiency investments and conservation efforts), and non-energy GHG mitigation measures.

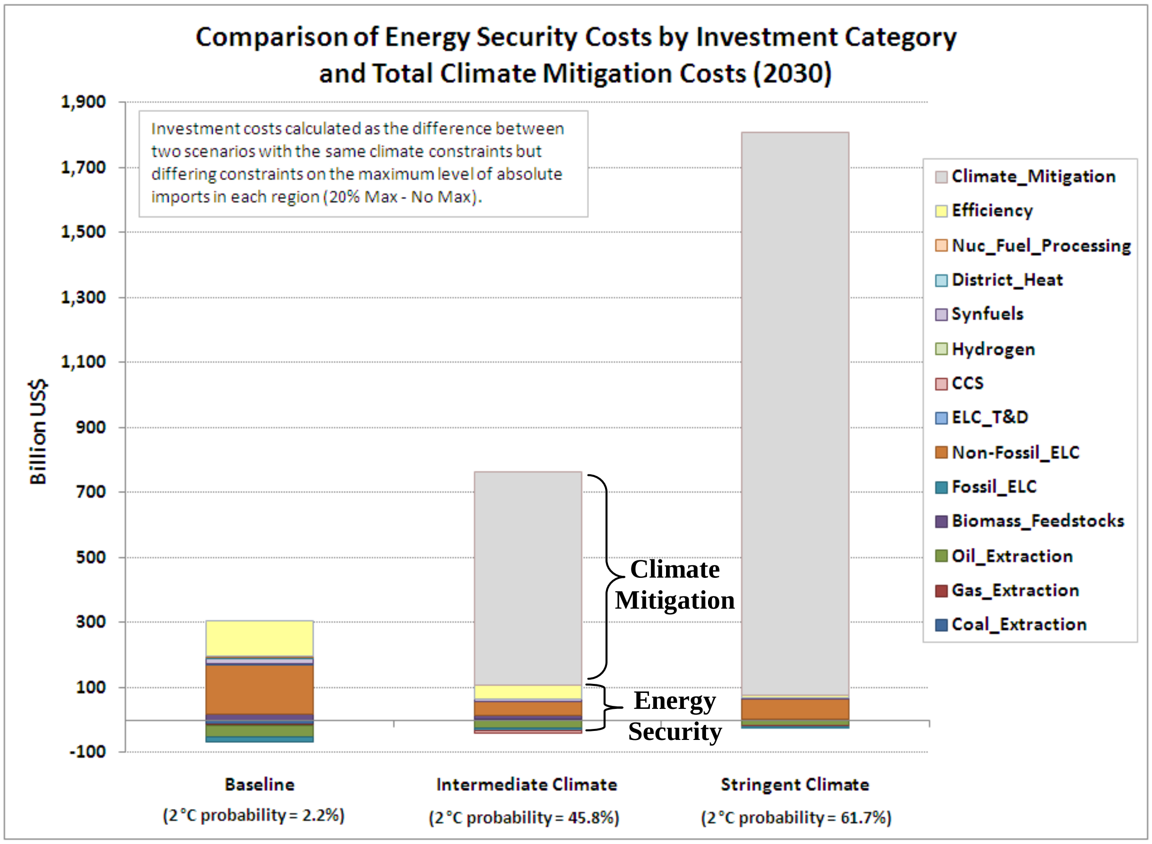


**Figure 102  Comparison of Energy Security Investments and Total Climate Mitigation Costs for Three Different Scenarios in 2030**

As one might anticipate, the impacts of climate, pollution, and security policies vary considerably by world region, for example, between industrialized and developing countries. Because developing countries will account for the bulk of development throughout this century, their aggregate energy system costs should be higher than in industrialized countries. This is illustrated in Figure 103, which shows total energy system costs as a share of GDP (*not* policy costs, hence *not* relative to the baseline) for industrialized and developing countries, respectively. It should be noted that the results shown here are somewhat distorted, since they only consider where energy expenditures are made and do not answer the critical question of “Who pays?” Financial transfers have not been modeled explicitly. Thus, industrialized country costs are underestimated, and developing country costs are overestimated. These distortions balance each other at the global level.

An interesting observation from Figure 103 is that for a given level of climate stringency the added costs of energy security tend to be higher for industrialized countries. This can be partly explained by the fact that these countries are at present much more dependent on imports than developing countries, a trend that is projected to continue through 2030, and even beyond, in the baseline scenario. Therefore, industrialized countries may have a more difficult time reducing their import dependence than developing countries, at least in the near term, because they are effectively locked in to using energy technologies that rely on imported resources. In contrast, most of the energy infrastructure that will ultimately be needed in developing countries has not yet been built, so it may be easier for these countries to adapt their systems, especially in the near term, to rely less on imports and more on domestically produced resources (e.g., renewables). Another interesting relationship shown in Figure 103 is that while for developing countries total energy costs exhibit a continuously upward sloping trend with respect to increasing climate stringency, costs increase rather slowly for industrialized countries and are actually fairly flat between the baseline scenario (1.3% of GDP) and scenarios with intermediate climate stringency (1.3% to 1.6%). This result demonstrates that a significant level of decarbonization can be achieved in industrialized countries at costs that are only marginally above the baseline.

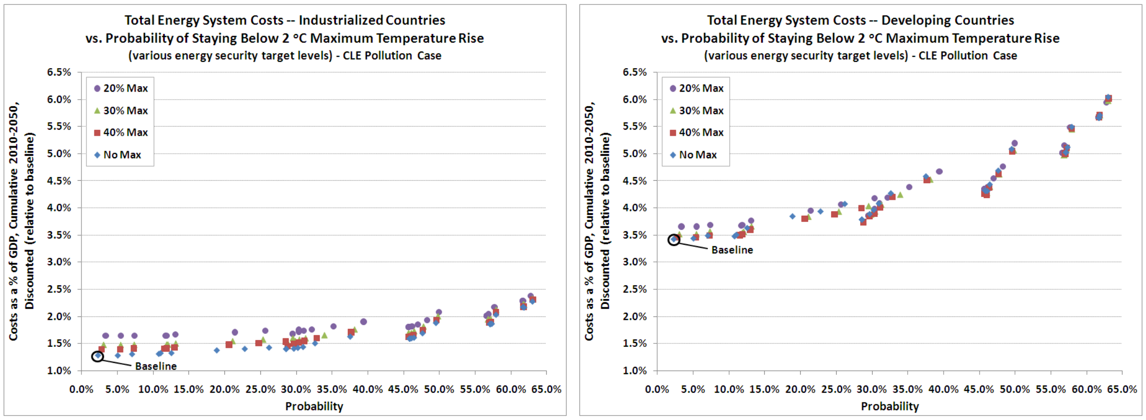


**Figure 103 Total Energy System Costs for Simultaneously Achieving Energy Security and Climate Mitigation Objectives (Industrialized and Developing Countries)**

## III.5 Conclusions

The energy system of the future could potentially develop along a number of different paths, depending on how society and its decision makers prioritize various, worthwhile energy objectives, including, but not limited to, climate mitigation, energy security, air pollution and human health, and affordability. These objectives are generally discussed in the context of different timeframes (e.g., security and pollution/health in the near term; climate in the medium to long term). Therefore, they frequently compete for attention in the policy world. An added challenge is that in many countries separate policy institutions are often responsible for dealing with the multiple objectives. As a result, important synergies between them are either overlooked or simply not understood, and the costs of reaching each objective individually are often overstated. In the future, cost-effective climate-pollution-security policies should account for the substantial added benefits of adopting a more holistic and integrated perspective, which addresses all of the objectives simultaneously.

This study has attempted to illuminate some of the key synergies, and to a lesser extent the trade-offs, between climate mitigation, energy security, air pollution and human health, and affordability, highlighting the main results and findings from an analysis that was conducted at IIASA in support of the Global Energy Assessment (GEA, 2011). One of the main findings of the analysis is that the synergies between the various objectives far outweigh the trade-offs. The trade-offs we refer to principally have to do with, first, the effect of climate, air pollution, and security policies on total energy system costs (relative to a baseline scenario) and, second, the impact of pollution control on radiative forcing.

A commonly discussed long-term goal for climate mitigation is the so-called "2 ºC target" – i.e., staying below 2 ºC maximum temperature rise, relative to pre-industrial levels, throughout the twenty-first century – which is thought to be needed to avoid dangerous interference with the climate system (Solomon et al., 2007). Maximizing the likelihood of achieving the 2 ºC target depends, above all, on making deep reductions in greenhouse gas emissions over the next several decades, a feat that will be principally accomplished by dramatically scaling up the utilization of zero-carbon energy technologies (nuclear, biomass, and other renewables) in the global energy mix. Specifically, meeting the 2 ºC target with greater than 50% probability in the long term requires zero-carbon energy shares (relative to total global primary energy supply) that are 25% or higher in the near term (2030) (Figure 95). Furthermore, because it is pollution-free and can be derived from a variety of sources, zero-carbon energy also has the potential to significantly decrease air pollution and its corresponding health impacts, as well as improve security through supply diversification and reduced import dependence. For example, Figure 96 and Figure 97 show that near-term targets for pollution reduction – both globally and in key developing world regions where air pollution and its health impacts are strongest – can be achieved just as effectively through decarbonization as they can through more stringent pollution control measures that are enacted in the absence of climate policy. The main pollution-climate trade-off centers around the small, but non-trivial, impact that lower levels of air pollutant emissions, namely climate-cooling aerosols (e.g., $SO_2$ and organic carbon), could have on the radiative forcing balance of the Earth. Figure 92 demonstrates that for a constant level of GHG emissions, stringent pollution control policies could potentially increase global temperatures by a few tenths of a degree, consequently lowering the probability of staying below 2 ºC maximum temperature rise by several percentage points. In terms of security benefits, substitution of domestically produced renewables (biomass, hydro, wind, solar, and geothermal) for imports of globally traded fossil commodities (coal, oil, and natural gas) could simultaneously reduce import dependence and diversify the energy resource mix away from one that relies too heavily on fossil energy.

Viewed from an holistic and integrated perspective, the combined costs of climate mitigation, energy security, and air pollution control come at a significantly reduced total energy bill if the multiple benefits of each are properly accounted for in the calculation of total energy *system* costs (i.e., when taking a systems view of the problem). For instance, Figure 98 shows that the total added costs of pollution control are cut significantly as the stringency of climate policy increases and the utilization of zero-carbon, pollution-free (hence, pollution control-free) technologies rises. In fact, pollution control cost reductions of greater than 80% are possible in the most stringent climate scenarios. Similarly, security costs also substantially decrease under increasingly aggressive levels of decarbonization (Figure 101). And in scenarios with extremely stringent climate policies, the added costs of security actually approach zero. While steps taken to mitigate the climate will necessarily add to total energy system costs compared to a baseline scenario, these climate costs will be substantially compensated for by the corresponding pollution control and energy security cost reductions.

An important caveat to this analysis is that it only does a partial economic accounting. It attempts to capture the multiple benefits of climate mitigation, energy security, and pollution control in terms of total energy system *costs*. However, the analysis largely ignores the significant economic *benefits* of pursuing these three objectives. For instance, it does not consider the avoided costs (i.e., benefits) of climate change (e.g., more frequent extreme weather events, impacts on global agriculture and food production) or of climate adaptation (e.g., construction of sea walls, relocation of coastal populations). Similarly, the benefits accruing from reduced health expenditures and increased life expectancies have not been monetized here.

### III.6 Acknowledgements

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## III.7 Appendix

*Appendix 1: Listing of 11 MESSAGE Regions by Country*

| 11 MESSAGE regions | Definition (list of countries) |
|---|---|
| **NAM** | **North America**<br>(Canada, Guam, Puerto Rico, United States of America, Virgin Islands) |
| **WEU** | **Western Europe**<br>(Andorra, Austria, Azores, Belgium, Canary Islands, Channel Islands, Cyprus, Denmark, Faeroe Islands, Finland, France, Germany, Gibraltar, Greece, Greenland, Iceland, Ireland, Isle of Man, Italy, Liechtenstein, Luxembourg, Madeira, Malta, Monaco, Netherlands, Norway, Portugal, Spain, Sweden, Switzerland, Turkey, United Kingdom) |
| **PAO** | **Pacific OECD**<br>(Australia, Japan, New Zealand) |
| **EEU** | **Central and Eastern Europe**<br>(Albania, Bosnia and Herzegovina, Bulgaria, Croatia, Czech Republic, The former Yugoslav Rep. of Macedonia, Hungary, Poland, Romania, Slovak Republic, Slovenia, Yugoslavia) |
| **FSU** | **Former Soviet Union**<br>(Armenia, Azerbaijan, Belarus, Estonia, Georgia, Kazakhstan, Kyrgyzstan, Latvia, Lithuania, Republic of Moldova, Russian Federation, Tajikistan, Turkmenistan, Ukraine, Uzbekistan) |
| **CPA** | **Centrally Planned Asia and China**<br>(Cambodia, China (incl. Hong Kong), Korea (DPR), Laos (PDR), Mongolia, Viet Nam) |
| **SAS** | **South Asia**<br>(Afghanistan, Bangladesh, Bhutan, India, Maldives, Nepal, Pakistan, Sri Lanka) |
| **PAS** | **Other Pacific Asia**<br>(American Samoa, Brunei Darussalam, Fiji, French Polynesia, Gilbert-Kiribati, Indonesia, Malaysia, Myanmar, New Caledonia, Papua, New Guinea, Philippines, Republic of Korea, Singapore, Solomon Islands, Taiwan (China), Thailand, Tonga, Vanuatu, Western Samoa) |
| **MEA** | **Middle East and North Africa**<br>(Algeria, Bahrain, Egypt (Arab Republic), Iraq, Iran (Islamic Republic), Israel, Jordan, Kuwait, Lebanon, Libya/SPLAJ, Morocco, Oman, Qatar, Saudi Arabia, Sudan, Syria (Arab Republic), Tunisia, United Arab Emirates, Yemen) |
| **LAC** | **Latin America and the Caribbean**<br>(Antigua and Barbuda, Argentina, Bahamas, Barbados, Belize, Bermuda, Bolivia, Brazil, Chile, Colombia, Costa Rica, Cuba, Dominica, Dominican Republic, Ecuador, El Salvador, French Guyana, Grenada, Guadeloupe, Guatemala, Guyana, Haiti, Honduras, Jamaica, Martinique, Mexico, Netherlands Antilles, Nicaragua, Panama, Paraguay, Peru, Saint Kitts and Nevis, Santa Lucia, Saint Vincent and the Grenadines, Suriname, Trinidad and Tobago, Uruguay, Venezuela) |
| **AFR** | **Sub-Saharan Africa**<br>(Angola, Benin, Botswana, British Indian Ocean Territory, Burkina Faso, Burundi, Cameroon, Cape Verde, Central African Republic, Chad, Comoros, Cote d'Ivoire, Congo, Djibouti, Equatorial Guinea, Eritrea, Ethiopia, Gabon, Gambia, Ghana, Guinea, Guinea-Bissau, Kenya, Lesotho, Liberia, Madagascar, Malawi, Mali, Mauritania, Mauritius, Mozambique, Namibia, Niger, Nigeria, Reunion, Rwanda, Sao Tome and Principe, Senegal, Seychelles, Sierra Leone, Somalia, South Africa, Saint Helena, Swaziland, Tanzania, Togo, Uganda, Zaire, Zambia, Zimbabwe) |

*Appendix 2: Modeling Energy Security Policy Within MESSAGE*

In modeling energy security policy within the MESSAGE integrated assessment framework, an absolute upper limit is placed on the total amount of energy that can be supplied by imports in a given region and year (see equation below). This limit, which begins in 2030 and remains fixed throughout the century,[71] is calculated as a share of baseline total primary energy supply (TPES) in the region in 2030.

$$I_i \leq X_i \bullet TPES_i$$

where:
- $I_i$: total energy imports into region $i$
- $X_i$: Maximum share of total primary energy supply in region $i$ that can be imported
- $TPES_i$: Total primary energy supply (= sum of imports, exports, and domestically produced energy)

The limit $X_i$ varies by scenario and ranges from 20% to 100%. The higher end of this range represents a non-constraining limit (i.e., a scenario where no explicit energy security policies are enacted), and the lower end represents a world where global energy trade flows are significantly reduced as a result of countries' efforts to achieve their security goals.

[71] This statement is true of all regions except South Asia. In order to avoid model infeasibilities, the absolute upper limit in South Asia in each year is not fixed at the 2030 level, but rather is set at particular share of the region's baseline TPES.

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